Annu. Rev. Energy Environ. 1997. 22:305–56

GEOTHERMAL ENERGY FROM THE EARTH: Its Potential Impact as an Environmentally Sustainable Resource

John E. Mock,[1] *Jefferson W. Tester,*[1] *and P. Michael Wright*[2]
[1]Massachusetts Institute of Technology, Energy Laboratory, Cambridge, Massachusetts 02139; [2]Energy & Geoscience Institute, University of Utah, Salt Lake City, Utah 84108

KEY WORDS: renewable energy, geothermal energy, electricity generation, district heating, drilling, heat pumps

ABSTRACT

Geothermal energy technology is reviewed in terms of its current impact and future potential as an energy source. In general, the geothermal energy resource base is large and well distributed globally. Geothermal systems have a number of positive social characteristics (they are simple, safe, and adaptable systems with modular 1–50 MW [thermal (t) or electric (e)] plants capable of providing continuous baseload, load following, or peaking capacity) and benign environmental attributes (negligible emissions of CO_2, SO_x, NO_x, and particulates, and modest land and water use). Because these features are compatible with sustainable growth of global energy supplies in both developed and developing countries, geothermal energy is an attractive option to replace fossil and fissile fuels. In 1997, about 7,000 MWe of base-load generating capacity and over 15,000 MWt of heating capacity from high-grade geothermal resources are in commercial use worldwide. A key question is whether these levels can grow to a point where geothermal energy is more universally available and thus have a significant impact on global energy supplies in the twenty-first century. Such an achievement will require the economic development of low-grade resources.

The current status of commercial and emerging technologies for electric power production and direct heat use is reviewed for the major geothermal resources including hydrothermal, geopressured, hot dry rock, and magma. Typically, high-temperature resources (>150°C) provide base-load generating capacity while lower-temperature resources provide energy for geothermally assisted heat pumps and for direct use in domestic, agricultural, and aquacultural heating applications.

1056-3466/97/1022-0305$08.00

Critical development issues relating to resource quality and distribution, drilling costs, and reservoir productivity are discussed in the context of their economic impact on production costs. Advanced drilling and improved heat mining methods are suggested as approaches to increase the worldwide use of geothermal energy by reducing field development costs. With these improvements, lower-grade resources can compete in growing global energy markets that are currently controlled by abundant and low-cost fossil fuels.

CONTENTS

THE GEOTHERMAL RESOURCE AND ITS HISTORY

Defining Geothermal Energy

In general terms, geothermal energy is the thermal energy stored at accessible depth in the earth's crust. Practically speaking, the exact specification of a geothermal resource depends in part on the specific application or energy service that is provided. Thermal energy in the earth is distributed between the constituent host rock and the natural fluid that is contained in its fractures and pores at temperatures above ambient levels. These fluids are mostly water with varying amounts of dissolved gases and salts; typically in their natural in situ state they are present as a liquid phase but sometimes may consist of a saturated or superheated steam vapor phase. Most geothermal resources presently usable for electrical power generation result from the intrusion of magma (molten rock) from great depth (>20 km) into the earth's crust. These intrusions typically reach depths of 0–10 km.

The ultimate sources of geothermal heat are associated with the upward conduction and convection of energy within the earth's core and mantle, which remain from the earth's formation, and with the generation of energy owing to radiogenic decay of naturally occurring elemental isotopes, particularly those of potassium, uranium, and thorium. Local and regional geologic and tectonic phenomena play a major role in determining the location (depth and position) and quality (fluid chemistry and temperature) of a particular resource. For example, regions of higher than normal heat flow are usually associated with tectonic plate boundaries and with areas of geologically recent volcanic events (younger than about one million years in the case of large magmatic intrusions of 10–100 km^3). This is why people frequently associate geothermal energy only with specific places such as Iceland, New Zealand, Japan (plate boundaries), Yellowstone National Park, or the Larderello field in Italy (recent volcanism) and neglect to consider geothermal energy opportunities presented by other regions.

For centuries, natural geothermal fluids have been used for bathing and cooking, but it was not until the early 1900s that geothermal energy was used for industrial purposes and for the generation of electricity in the Larderello steam fields of northern Italy. In all cases where geothermal energy is utilized, certain conditions must be met before one has a viable geothermal resource. The first requirement is accessibility. This is usually achieved by drilling to depths of interest, frequently using conventional methods similar to those used to extract oil and gas from underground reservoirs. The second requirement is sufficient reservoir productivity, which depends on the type of geothermal system being exploited. In some cases, as depicted in Figure 1, one needs to have sufficient quantities of hot, pressurized natural fluid contained in a confined aquifer with high rock permeability and porosity to insure long-term production at economically acceptable levels from a drilled well. In other situations, one only needs to have a sufficiently hot rock reservoir whose permeability can be enhanced to produce a system for extracting energy at acceptable rates. The term hot is relative, as it depends on the specific application. The geothermal resource actually spans a continuum in at least three dimensions: temperature, depth, and permeability/porosity. Low-grade systems, which may or may not contain natural fluids, involve temperatures from just above ambient to about 150°C. The average geothermal gradient quantitatively establishes the relationship between temperature and depth. Generally, low-grade systems have lower gradients and thus are located deeper in the crust. If fluids are not present, then in situ permeabilities and porosities are intrinsically low or the reservoir system is located above the natural water table. The converse is true if natural fluids are available

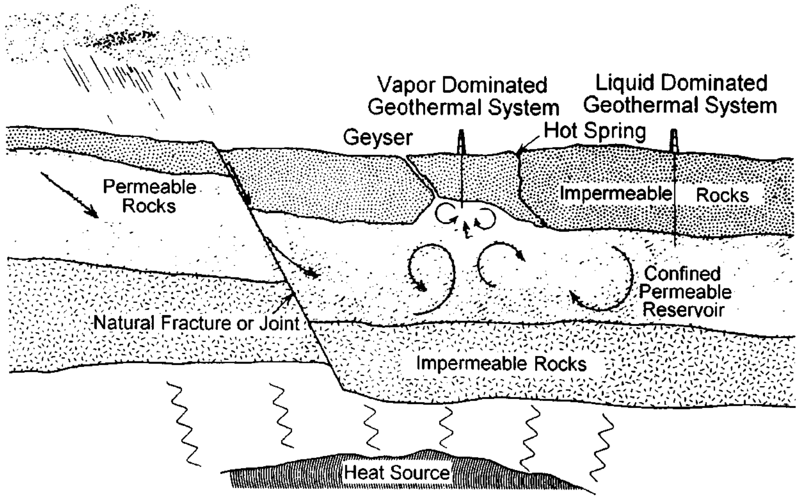


Figure 1 Conceptual geologic setting for an active hydrothermal system.

for heat extraction. High-grade resources are at the other end of the continuum, characterized by hot fluids contained in high permeability and porosity host rock and at relatively shallow depths. Obviously, reservoirs that produce fluid of low salinity spontaneously (under pressure) are easier to exploit, and if they exist at high temperature at shallow depths, we truly have a high-grade resource.

In the Context of Global Sustainability

As the world's population increases and nations attempt to further their social and economic development, increasing levels of stress are being placed upon the natural environment. To cope with rising rates of natural resource consumption and spiraling levels of environmental damage, governments and institutions worldwide are becoming more and more interested in how their finite resources can be deployed to ensure an acceptable future for the human race. They are striving for ways to ensure the sustainability of our atmospheric, hydrologic, mineral-resource, energy-resource, biological, social, and economic systems. For further discussion see (1–5).

Availability of adequate energy supplies at acceptable costs is prerequisite to social and economic progress. In past decades, there was concern that fossil fuels were being depleted too quickly. Today, however, with abundant oil, gas, and coal reserves, the focus has shifted to how to mitigate environmental degradation and reduce possible adverse health effects. Although we have found ways to curtail emissions of sulfur and nitrogen oxides resulting from fossil-fuel combustion to meet environmental regulations, the appropriate control technology adds cost. In developing countries, these increased costs may be unacceptable. The mitigation of greenhouse gas buildup from carbon dioxide (CO_2) emissions is even more challenging. While technologies for capturing CO_2 from stack gases exist, disposal and sequestration methods have not yet been demonstrated to levels required to achieve major reductions in emissions. Furthermore, CO_2 capture consumes energy, thereby increasing resource consumption rates. The economic impacts of all of this are significant. For example, a recent review by Herzog & Drake (6) projects cost increases for electricity production of 40–230% with CO_2 capture and disposal. Consequently, it is likely that non-carbon fuels will be needed to reduce the buildup of CO_2 in the atmosphere. Despite the enormity of these global concerns, generating plants using fossil fuels are being built at increasing rates worldwide because they are generally the least costly means of meeting growing power demand. In fact, since the mid-1980s, public perception is that we do not have an energy crisis at all—the general public, for the most part, has not made the connection between increasing fossil energy consumption and environmental damages on a regional or global scale, with the exception of large ocean-tanker oil spills. Without an international commitment to reducing or limiting fossil energy consumption, it will be difficult to mobilize and support the energy research and development (R & D) levels required to develop viable alternatives quickly enough to have a real impact in the next century. Furthermore, without national or international targets for limiting CO_2 emissions, or regulatory policies for including the environmental externalities of fossil fuel use in the prices paid for them, alternative, more environmentally acceptable energy systems will continue to face extremely stiff competition in today's energy markets.

Nonetheless, accelerated commercialization of renewable-energy resources is an option being promoted by a growing segment of society. The reasons are well known. Renewable-energy resources (*a*) have environmental advantages over other energy sources; (*b*) are available locally, mitigating the costs and many other problems of importing, moving fuel minerals around the globe, and maintaining security of supply; and (*c*) are supported by enormous resource bases. However, under present economic conditions, renewable-energy resources will not be able to satisfy even new demand for energy in the foreseeable future, let alone replace existing fossil fuel use. In the decades to come, when energy use must rise dramatically in order to support economic growth for a growing world population, we must find significantly better ways to obtain and use energy resources. This brings us to the concept of sustainability.

In the strictest sense, the sustainable utilization of a resource, of whatever kind, is dependent on its initial quantity, its rate of generation, and its rate of consumption. Consumption cannot be sustained over a time period in which the resource is being depleted faster than it is created or replaced. Even if the rate of consumption exceeds the rate of generation, energy production can nevertheless be sustained over some time period dependent upon the magnitude of the difference between these rates and the initial amount of the resource available. These issues have direct relevance to geothermal systems, particularly in the context of the spatial dimensions of a specific resource.

The term "sustainable development" was used by the World Commission on Environment and Development (the Brundtland Commission) to mean development that "meets the needs of the present generation without compromising the needs of future generations" (7). Schmidheiny (8) introduced the related concept of eco-efficiency to frame sustainable industrial development for the Rio Earth Summit. Operationally similar definitions have been provided by others, such as New Zealand's Resource Management Act (3) and the Worldwatch Institute (1). It is really not necessary to have a single quantitative definition of sustainability—it is a concept and a way of thinking that captures many environmentally sound features, including waste and emissions minimization, decreased consumption of depletable natural resources, and increased use of renewable energy and materials resources.

To deal with the sustainability of energy supply in general, we must consider growth in demand and the fundamental characteristics and interactions among all available and reasonably foreseeable energy sources. In principle, if one resource becomes depleted, we need only have an environmentally and economically acceptable substitute available in sufficient quantity to ensure that future generations are able to meet their energy needs. In the evolving global portfolio of energy futures, renewable energy systems should eventually play a larger role. While the solar, wind, and biomass options have very active programs and large advocacy constituencies, the geothermal option has been undervalued in our view, largely because of misperceptions about the nature of the geothermal resource, particularly its magnitude, worldwide distribution, and renewable characteristics.

In the context of the Worldwatch Institute's sustainability definition, geothermal energy is considered to be the only renewable that does not depend on sunlight; however, "it must be tapped slowly enough so as not to deplete the accessible reservoir of heat, and thus be truly renewable" (1). However, given the magnitude and distribution of the global geothermal resource, this restriction is neither practical nor necessary since the resource is large, and improving technology will allow geothermal energy to contribute for centuries (see for example 9–11).

Kozloff & Dower (12) point out that whether a resource can be said to be renewable depends on the time frame under consideration. They suggest that if continuous production of an energy fuel can be maintained, by today's projections, for 300 years or more, then that fuel can be considered renewable, since technical advances during that time will have rendered today's perspective obsolete. For geothermal resources, the renewability concept has a special connotation. In all practical situations, some degree of local depletion of geothermal energy within a specific reservoir occurs during production. But renewal of the thermal energy content will occur by natural processes of heat conduction from surrounding hot rock; by decay of indigenous radioisotopes such as those of potassium, thorium, and uranium; and by water recharge. With average rock thermal diffusivities of 10^{-6} m^2/s, heat conduction rates are slow enough to require a substantial time period to restore the thermal energy content of a locally depleted reservoir. Typically, within a period of time less than 10 times the production period, essentially complete recovery of original temperatures will occur (11). Of course, for hydrothermal systems, natural water recharge rates may be extremely slow unless artificially supplemented. Other sustainable features of geothermal energy relating to its environmental attributes are discussed below.

Characterizing Geothermal Resources

Geothermal resources are commonly divided into four categories: hydrothermal, hot dry rock, magma, and geopressured.

HYDROTHERMAL Hydrothermal resources are typically located at depths of 1–4 km and contain steam or liquid water up to 350°C in a convectively active, permeable region of porous rock. The highest grade, vapor-dominated systems occur rarely, and several have been exploited to produce electricity. Examples are the Larderello field in Italy, The Geysers field in California, and the Matsukawa field in Japan. Liquid-dominated resources are much more common and are widely distributed globally. High-quality fields containing relatively low-salinity water under pressure at temperatures up to 350°C have been identified in many regions, including the Western United States, Mexico, Central and South America, New Zealand, Iceland, China, Japan, Indonesia, the Philippines, Italy, Turkey, and several countries in eastern Africa. Liquid-dominated resources with fluid temperatures ranging from about 40 to 300°C are being used commercially throughout the world for generating electricity and for providing process and residential heat.

HOT DRY ROCK The term "hot dry rock" has been used to describe geothermal systems where fluids are not produced spontaneously. In many situations, these are really non-productive hydrothermal systems that require stimulation before energy extraction can be achieved at economically viable rates. Such systems can occur within or at the margins of an active hydrothermal reservoir system or, at another extreme, may be associated only with above-average heat flow in a conduction-dominated geologic setting. For cases where significant porosity and natural water are present in open fractures or in rock matrix permeability, the classification "hot wet rock" has been used. In this review, we will treat hot wet rock as a subcategory of hot dry rock (or simply HDR).

In principle, hot dry rock systems are available everywhere just by drilling sufficiently deep to produce rock temperature useful for heat extraction—usually taken to be $>150^{\circ}$C for producing electricity and >50–100°C for direct heat use. Therefore, for base-load electric power generation in low-grade, low-gradient regions (20–40°C km^{-1}), depths of 4–8 km are required, while for high-grade, high-gradient systems ($>60^{\circ}$C km^{-1}), 2–5 km are sufficient.

MAGMA Magma resources consist of partially or completely molten rock encountered at accessible depths (say <7 km) in regions of recent volcanic activity such as near the Kilauea Iki volcano in Hawaii or in the Yellowstone National Park region in Wyoming. Magma's very high temperatures, in excess of 650°C, make it particularly attractive for efficient electric power production or for high-temperature industrial process heat applications.

GEOPRESSURED Geopressured resources consist of hot high-pressure brines containing dissolved natural gas (methane). In addition to containing thermal and hydraulic energy, they also have chemical energy content stored in the dissolved methane. Such resources occur in many on-shore and off-shore petroleum basins worldwide. For example, the Gulf Coast region, along the Texas and Louisiana coasts, has abundant geopressured resources containing moderately saline brines (up to 200,000 ppm total dissolved solids [TDS]) at temperatures from 150 to 180°C and pressures up to 20,000 psi (1,400 bar) at depths of 3–5 km. For these resources, the thermal energy content represents about 58%, the hydraulic part about 10% at best, and the hydrocarbon chemical energy about 32%.

We discuss the current status of geothermal resource developments further below, but for detailed descriptions readers should consult such primary references as Armstead & Tester (11), Armstead (13), DiPippo (14), Rowley (10), Duchane (15), and Kruger & Otte (16).

The Path Forward

Table 1 presents US and worldwide estimates of the resource base for various geothermal resource types. Although the natural hydrothermal, magma, and geopressured systems have reasonably large resource bases and will be exploited when technical and economic conditions are favorable, their distribution worldwide is controlled by prevailing natural geologic conditions. They are not ubiquitously located worldwide. In terms of total energy use, electrical power generation is now and will continue to be for the immediate future the

Table 1 Geothermal resource base estimates—total thermal energy content in place[a]

Resource type	10^3 quads[b] US	10^3 quads[b] World
Hydrothermal (vapor and liquid dominated)	9.6	130
Geopressured[c]	170	540
Magma[d]	500–1,000	5,000
Hot dry rock[e]		
Moderate to high-grade ($\nabla T > 40°C/km$)	6,000	26,500
Low-grade ($\nabla T < 40°C/km$)	24,000	78,500
Total all grades	30,000	105,000

[a]Sources: (10, 11, 13, 15). US figures based in part on USGS estimates (51–53).

[b]1 quad $\equiv 10^{15}$ BTU $\approx 10^{18}$ J. 1996 worldwide commercial energy demand = 350 quads. 1996 US commercial energy demand = 85 quads.

[c]Includes hydraulic and methane energy content.

[d]To depths of 10 km and initial rock temperatures > 650°C.

[e]To depths of 10 km, and initial rock temperatures > 85°C.

predominant end-use for geothermal resources. Essentially all generated electricity is baseload and goes to the transmission grid. To date, only high-grade hydrothermal systems have been developed for commercial electric power generation and district heating applications. Hydrothermal resources have been utilized most effectively when resource location and user demand coincide. Such is the case in developing countries like Indonesia and the Philippines, in parts of Central America, and in the Western United States.

Although geopressured and magma resources have substantial potential, in order for geothermal energy to become universally available and a major player in supplying energy worldwide in the next decade, hot dry rock (HDR) systems must be utilized. Fortunately, HDR is by far the largest, most widely distributed resource, but appropriate heat mining technology has not yet become commercially available. As discussed below, competitive universal geothermal energy requires the development of advanced heat extraction techniques for HDR to stimulate production, such as better methods of hydraulic fracturing, as well as improved drilling techniques to reduce drilling costs so that even low-grade, low-gradient regions can be economically developed. At this point it is instructive to review the current state of commercial geothermal energy development.

COMMERCIAL DEVELOPMENT

Direct Thermal Energy Utilization

Long before electricity was produced early in this century from high-temperature geothermal resources, low-temperature resources were being used for heating, bathing, and cooking. While geothermal spas are still popular, low-temperature resources are finding increasing use in a wide variety of commercial applications, ranging from 10°C (50°F) for soil warming to 150°C (300°F) for cement drying. Even the thermal capacity of the earth at shallow depths is being exploited in operating highly efficient geothermal heat pumps (GHPs). Figure 2 shows several systems for direct thermal and heat pump applications.

Historically, geothermal energy was first used in the United States by small resorts and district heating systems. In 1960, electric power generation on a commercial scale began in The Geysers field in California, located about 80 miles north of San Francisco. The oil price shocks of the 1970s spurred interest in the use of geothermal resources as an alternative energy source. In 1978, the US Department of Energy (DOE) initiated numerous programs that significantly accelerated the growth of this industry. These programs included exploration, resource assessments, technical assistance, feasibility studies, loan guarantees, and support of state resource and commercialization activities. Various federal and state tax credit programs were adopted to incentivize the direct use of geothermal resources (17, 18). By 1994, geothermal energy provided about 1.4×10^{16} J (13 trillion Btus) annually for direct heat applications in the United States (as shown in Table 2) (19), mainly in California, Oregon, Idaho, Nevada, Utah, New Mexico, Wyoming, South Dakota, Texas, and New York.

Legal rights to geothermal fluids are complicated by the fact that geothermal resources are related to water, gas, and minerals, to both surface and subsurface

Table 2 Geothermal direct heat uses in the US circa 1994[a]

Type of use	TJ/Year^{-1}	Billion Btu/Year^{-1}
Space and district heating	1,388	1,317
Bathing and swimming	1,606	1,524
Agricultural drying	299	284
Greenhouses	709	673
Fish/animal farming	1,360	1,290
Industrial process heat	332	315
Snow melting	3	3
Air conditioning	5	5
Geothermal heat pumps	8,188	7,769
Total	13,890	13,180

[a]Source: (19).

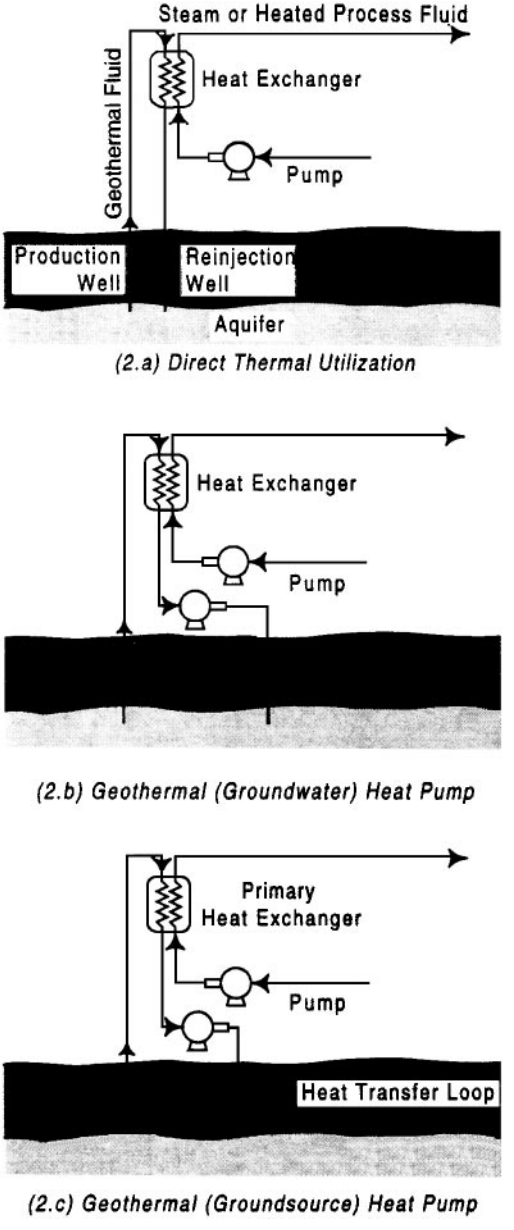
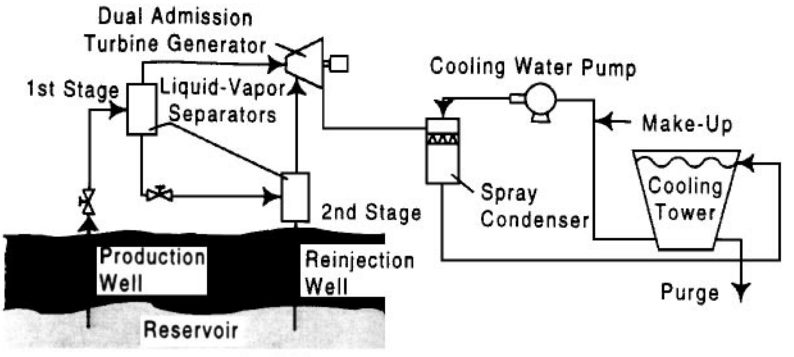
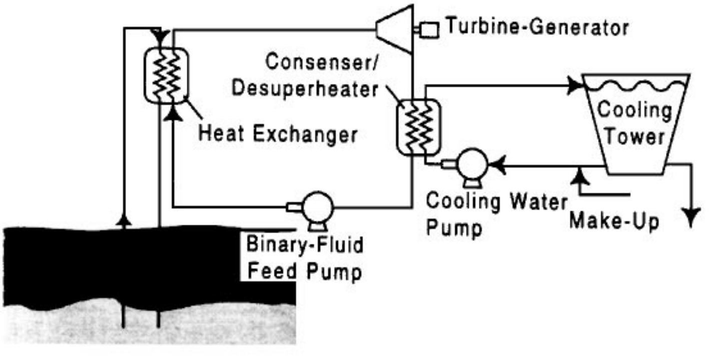


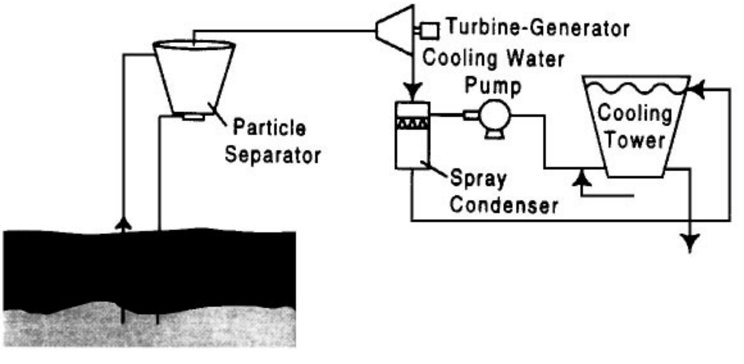
Figure 2 Energy utilization options for geothermal resources.



(2.d) Two-Stage Flash Cycle



(2.e) Binary Fluid Cycle



(2.f) Direct Steam Cycle

Figure 2 (*continued*)

estates, and to both water and mineral rights. To a large extent, the legal and regulatory aspects in the United States have been addressed by Congress and state legislatures. Bloomquist (20) has summarized pertinent geothermal definitions, ownership and leasing information, injection requirements, and the federal and state agencies involved. In other countries, the resource typically belongs to the state. Some countries allow leases of geothermal reservoir areas for the purpose of production, whereas others prefer to reserve development to state-owned companies, furnishing steam to power plants built by the private sector.

Exploration is generally the first step in the exploitation of geothermal resources—a step consisting of locating reservoirs and siting production wells. Wright (21) has described the various exploration methods and techniques, adapted (and improved upon) from the fields of geology, geochemistry, geophysics, and hydrology. They include geologic mapping, chemical geothermometry, age dating of geothermal fluids, fluid inclusion studies, isotope studies, and electric and magnetic field strength mapping (electromagnetic/magnetotelluric/self-potential), seismic (microearthquake) surveys, and gravity surveys.

Although the usable resource base of low- and moderate-temperature geothermal resources is very large, development of direct-heat uses is proceeding slowly. There is essentially no direct-heat geothermal industry or infrastructure in the same sense that there is an electrical-power generation industry. Each direct-heat system is a separate design, and few consultants or contractors are trained and experienced in the direct use of geothermal resources. With low costs for natural gas and heating oil, this situation may not change soon.

Engineering technologies for the use of low-temperature energy sources are well established for use with conventional fuels. However, to design and operate such facilities with an unfamiliar resource—or even to determine whether the use of geothermal fluids is economically or technically feasible for any given application—is often beyond the technical expertise of engineers trained in conventional methods. Even fewer engineers have training or experience in finding, producing, and managing geothermal reservoirs. The Geo-Heat Center (GHC) at the Oregon Institute of Technology (OIT) was established to provide potential users with technical assistance, including design and economic analyses, resource information, review of project plans, consultation on equipment and material selection, and analyses of operational problems.

Industrial applications generally need moderate- to high-temperature geothermal resources. Industrial uses include enhanced oil recovery (90°C), ore or heap leaching operations using selective chemical dissolution to extract precious metals (110°C), dehydration of vegetables (130°C), mushroom growing (60°C), pulp and paper processing (200°C), hay drying (60°C), timber drying (90°C), and diatomaceous earth drying (182°C) (17, 18).

The first modern industrial use in the United States was a vegetable dehydration plant at Fernley, Nevada. When the plant was built in 1978 to process onions, the geothermal fluid was used only to supply heat for the dehydration process. However, the advantages of using the fluid in the wet preparation stage quickly became apparent. Because of its oxygen-free and essentially bacteria-free nature, the geothermal fluid maintains a bacterial count well below prescribed health standards. Advantages of using geothermal fluids include significantly increased production rates, elimination of the potential fire hazards of other fuels, and no discoloration of the products through scorching.

Two gold-mining companies use a novel application developed by the Earth Sciences Division, University of Nevada, Las Vegas to enhance their ore-leaching operations with warm geothermal fluids. The addition of heat to the cyanide leaching solution provides two significant advantages: year round operation independent of prevailing weather conditions, and increased precious metal recovery. Geothermal fluids are also finding increasing use in aquaculture to raise catfish, trout, perch, bass, tilapia, sturgeon, shrimp, and tropical fish. Water quality and disease control are very important in fish farming. The benefit of a controlled rearing temperature through the use of geothermal fluids can increase growth rates by 50–100%, increasing significantly the number of harvests per year.

Greenhouses are among the fastest growing applications; many commercial crops (including flowers, house plants, vegetables, and tree seedlings) can be raised profitably, making geothermal resources economically attractive, especially in cold climates. As one example, a 7,000 m^2 (75,000 ft^2) greenhouse in Utah using geothermal energy to raise roses reduced heating costs by 80% and overall costs by 35% (17). The wide variety of greenhouse equipment, grower's preferences, and resource temperatures makes the selection a complicated process. To assist the prospective developer, the GHC developed a comprehensive spreadsheet, which helps evaluate the costs (both capital and operating) of the six major types of greenhouse heating systems (22). Large geothermally heated greenhouses are currently operated in Italy, Iceland, Hungary, and the United States (in New Mexico, Utah, and California).

Currently there are 23 geothermal district heating systems in the United States, including the nation's oldest at Boise, Idaho; the 65,000 m^2 (700,000 ft^2) system on the OIT campus; the municipal detention facility system in Yakima, Washington; and the nation's largest geothermal district heating system in San Bernardino, California. To assist communities and developers in evaluating the costs and benefits of such systems, Washington State University and the GHC have prepared comprehensive computer programs for geothermal direct use cost evaluation (23).

In terms of future potential in the United States, we note that the most recent compilation of low- and moderate-temperature geothermal resources in 10 western states contains information on 8977 thermal wells and springs that are in the temperature range of 20–150°C. Data and maps are available for Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, and Washington. Resources with temperatures greater than 50°C and located within 8 km of a population center were identified for 271 cities and towns; 50 sites were judged high in priority for near-term comprehensive resource studies and development (24, 25). Older data are available for the rest of the United States (26). Like the nation's high-temperature geothermal resources, the resources suitable for direct-heat applications are generally underdeveloped compared with their potential.

Geothermal Heat Pumps

The term "Geothermal Heat Pump" (GHP) is generic for all heat pumps that utilize the earth's thermal capacity as an energy source (for heating) or an energy sink (for cooling). At shallow depths greater than about 1–2 m (3–6 ft), the earth maintains a relatively constant temperature, warmer on average than the air above it in winter, cooler in summer, making possible typical GHP coefficients of performance (COPs) of 4.0 or better. According to an EPA study (30), this high efficiency of GHPs can reduce energy consumption by 23–44% over air source heat pumps and by 63–72% over electric resistance heating and standard air-conditioning equipment.

The earth's thermal capacity can be utilized either directly or indirectly, for example, by using groundwater as an intermediary heat transfer agent. The concept of GHPs is occasionally expanded to encompass the relatively few heat pumps that utilize lake or river water. Rafferty (27) classifies GHPs in three groups: ground-coupled, groundwater, and hybrid (see Figure 2). In the first type, a closed loop of pipe is buried horizontally beneath the frost zone, or vertically 30–120 m (100–400 ft) deep, and filled with a water-based antifreeze solution that extracts heat in a closed circulating loop from buildings in summer and deposits it in the earth. In the winter the system is reversed—heat is extracted from the earth and carried into the building. Waste heat from a GHP can provide domestic hot water at little cost (28).

The second type of GHP, the oldest [used in the United States since the 1930s (29)] and until recently the most widely used approach, delivers groundwater to a heat exchanger installed in the heat pump loop, then disposes of it on the surface or in an injection well. These systems have gradually dropped in popularity as increased environmental regulations designed to prevent contamination of surface waters or aquifers have favored the adoption of the totally enclosed ground-coupled system. The third type, the hybrid system, which combines a ground-coupled system with a cooling tower, is used primarily in commercial buildings. Due to the high cost of meeting peak cooling loads, hybrids incorporate a cooling tower, which allows the designer to size the ground loop for heating loads and to use the tower to help meet the much larger peak cooling loads (27).

To help mitigate the perceived energy crisis in the early 1970s, the US government initiated activities to assist the commercialization of GHPs. This effort also included publications such as (31, 32) and Washington State Energy Office's 1982 GHP computer programs. Several large projects were supported including the 1982 installation of a 300-ton (where 1 ton $=$ 3517 W $=$ 200 Btu min^{-1}) heat pump in the county courthouse in Ephrata, Washington. Previously the annual bill for operating the oil-fired boiler was \$14,000–\$22,000, depending on the severity of the winter. After GHP installation, costs fell to approximately \$2,400 per year (33). Other demonstration projects included the 37,200 m^2 (400,000 ft^2) climate-controlled Oklahoma state capitol using 277 independently controlled GHPs, and New Jersey's Stockton College, home of the largest school GHP system (1600 tons).

GHPs can also utilize the thermal energy content of existing commercial water supply systems. Section 3013 of the Energy Policy Act of 1992 directed the government to "encourage states, municipalities, counties, and townships to consider allowing the installation of geothermal heat pumps, and, where applicable, and consistent with public health and safety, to permit public and private water recipients to utilize the flow of water from, and back into, public and private water mains for the purpose of providing sufficient water supply for the operation of residential and commercial geothermal heat pumps." In designing and constructing such systems extreme care must be taken to prevent any contamination of the water supply system.

The United States lags behind other countries in taking advantage of geothermal heat-pump technology. To accelerate commercialization of GHPs, the government [DOE and Environmental Protection Agency (EPA)] and public and private organizations (including Edison Electric Institute, National Rural Electric Cooperative Association, Electric Power Research Institute, Consortium for Energy Efficiency, and the Electric Power Industry, which has more than 70 electric utilities and over 50 trade allies) established in 1994 the Geothermal Heat Pump Consortium (GHPC), which initiated a \$100 million, six-year program. Specific goals of the program are to reduce greenhouse gas emissions, improve energy efficiency, and reduce heating/cooling costs, increasing annual GHP sales in the United States from 40,000 units per year in 1994 to 400,000 units per year by the year 2000. Since each residential unit can reduce summer and winter peak loads by 1–2 kWe and 4–8 kWe respectively, achieving this goal will offset each year the need for the operation of 2000 MWe capacity, reducing greenhouse gas emissions by 1.5 million metric tons of carbon equivalent (MMTCE) per year (29, 34). By the year 2010, the reduction in emissions could reach 12.9 MMTCE annually.

The GHPC developed a three-pronged technology-transfer program. The first prong (First Cost Competitiveness) entails developing innovative financing methods and conducting research and development (R&D) to reduce the cost and time of installing ground-coupled systems. The second prong (Technology Confidence Building) includes demonstration projects, model standards, design manuals, and seminars to reach customers, opinion leaders, trade allies, and educational institutions. The third prong (Infrastructure Strengthening) includes acquiring data for design assistance, training contractors and architectural and engineering (A&E) firms, developing model state and local laws and regulations, and removing legal and institutional barriers.

Assuming these initiatives are successful, one can estimate the potential impact of GHPs on US energy consumption. Currently, there are an estimated 25 million homes in the United States that have electric central air conditioning and heating systems without access to natural gas. Replacement of these units alone with GHPs over the next several decades would result in a savings of 24,000–48,000 MWe during summer peak-demand periods and 48,000–96,000 MWe during winter peak-demand periods. This rough estimate illustrates what could be done in only one sector—existing residential homes in the United States with electrical central air conditioning. It does not include new home construction or electrical energy used in heating and cooling buildings in the industrial or public sectors.

Electric Power Production

ECONOMIC ISSUES In the United States, moderate- and high-temperature hydrothermal resources, in the range 105°C (220°F) to 350°C (660°F), are located at accessible depths mainly in the western third of the continent, Alaska, and Hawaii. At the present time, there are about 2800 MWe of installed generating capacity in the United States, enough to serve the domestic needs of about three million people. Thus, geothermal energy has moved beyond the experimental stage. The commercial production of electricity from geothermal resources in the United States began in 1960 and has grown ever since. Power plants are currently on line in California, Nevada, Hawaii, and Utah. Approximately 7% of California's electricity and about 25% of the Island of Hawaii's electricity comes from hydrothermal resources. There is substantial expansion and new-development potential in these states, and there is also potential for developing power plants in the near term in Alaska, New Mexico, Idaho, Montana, and Oregon.

There are no recent comprehensive and well-documented assessments of the potentially recoverable hydrothermal resource in the United States. Brook et al (35) gave the estimate of 95,000–150,000 MWe from known and undiscovered hydrothermal reservoirs having a projected 30-year lifetime, but most people now believe this number is too high. Wright (36) gave a rough estimate of 4800 MWe of electrical power available for development, beyond current development, over the next 10 years from known hydrothermal systems in the contiguous 48 states. Hawaii could add 100–200 MWe and Alaska could add 50–100 MWe to the total in this time frame. Most of the large disparity between Brook's numbers and Wright's numbers originates from the geologic reasoning that there are many hidden, undiscovered hydrothermal resources, especially in the low-to-moderate temperature range. New and significantly improved technology will be needed to locate these hidden hydrothermal systems. The amount of exploration work being conducted to locate new hydrothermal systems in the United States is small at the present time, owing to the low cost of power generation from natural gas. However, some exploration work is being conducted in known resource areas to prepare for expansion when electricity demand increases.

Wright (9) argues that the traditional geothermal project analysis underestimates the sustainability of production from a geothermal resource. Such analyses are usually done to demonstrate the financial viability of the project and consequently make very pessimistic estimates of resource depletion. Field production is not only simulated in feasibility studies but also carried out in practice in a very conservative way. The geothermal field is said to be depleted when it will no longer sustain some chosen level of generation. At this point, however, significant quantities of heat remain in the rock-fluid reservoir system. Using traditional economic analysis, a residual value for the geothermal resource after initial exploitation is not recognized since its present value would be only a few percent of the project cost. In addition, no account is taken of future improvements in technology, future costs of competing energy supplies, compensation for environmental benefits, or other factors that may enhance the economics and add to the amount of energy we can reasonably expect to recover from a geothermal system. The International Energy Agency (IEA) is contemplating new studies that take into account the total thermal energy in the geothermal resource, projected improvements in extraction and utilization technology, and the likelihood of improved economics that recognize the environmental benefits of geothermal energy (37).

POWER PRODUCTION SYSTEMS Hydrothermal, non-concentrating solar thermal, and ocean thermal resources share the common disadvantage of having inherently low resource temperatures. One technique of increasing their quality as well as their transportability is to convert their available energy into electric power. In practical terms, the efficiency of such conversion processes is limited by resource temperatures and by prevailing ambient conditions for heat rejection. Efficiencies for converting geothermal resources at temperatures below 200°C to electricity are substantially less than those of fossil-fuel–fired or nuclear-powered plants, typically 10–20% versus 35–50% in terms of the ratio of work produced to heat supplied (or Carnot-type, Second Law efficiency) (38). New technologies have been improving the practical efficiency of power production toward its ideal thermodynamic limits to provide an economical process. For example, for a number of these low-temperature alternative energy sources, several hydrocarbons and their halogenated derivatives have been proposed as working fluids rather than steam (13, 38).

Figure 2 illustrates several types of utilization schemes for electric power production and direct use. Typically a Rankine cycle of some type is employed. In the multistage flash system shown, the pressure of the produced geofluid is reduced to generate saturated vapor and liquid phases. The vapor fraction is then expanded in a condensing steam turbine/generator to produce electric power. The liquid fraction is flashed again to a lower pressure with the vapor generated expanded in the turbine from a lower starting pressure. Although the process can be repeated for multiple stages, two-stage systems are usually the best choice economically.

For vapor-dominated resources, such as those at The Geysers field in California, a direct steam turbine condensing cycle is used. Particulate matter is removed from the steam before it enters a low-pressure turbine that employs conventional materials and designs.

When natural geofluids contain significant amounts of non-condensable gases, a direct steam or flashing cycle is not a good choice. Indirect binary-fluid or two-phase expander (13, 38) cycles are much more efficient. Binary-fluid cycles are closed-loop Rankine cycles that involve a primary heat exchange step in which a secondary working fluid is vaporized, expanded through a turbine/generator, and condensed, as shown in Figure 2. Binary-fluid systems tend to operate at somewhat higher work-to-heat rate efficiencies for geothermal fluid temperatures below 200°C and are particularly well suited to take advantage of low ambient temperatures for cooling (38).

US GEOTHERMAL POWER INDUSTRY The US geothermal industry is composed of more than 50 companies; the major US field developers are Caithness Corporation, CalEnergy Company, Inc.; Calpine Corporation; Constellation Energy, Inc.; ESI Energy, Inc.; Ormat International, Inc.; Oxbow Power Services, Inc.; and Geothermal Division, Unocal Corp. US utilities generating or purchasing geothermal power include Hawaiian Electric Light Company, Northern California Power Agency, PacifiCorp, Pacific Gas & Electric Co., Sierra Pacific Power Co., Southern California Edison, and Utah Municipal Power Agency. Direct employment in US geothermal energy operations is estimated to be about 14,000 jobs, and using a multiplier of 2.5, the indirect effect is a minimum of

35,000 additional jobs as suggested by Meidav & Pigott (39). The US geothermal power industry currently operates about 2300 MW of generation capacity to produce about 17 billion kWh year^{-1}, in four states—California, Hawaii, Nevada, and Utah (40). Geothermal energy is the second largest grid-connected renewable electricity source, exceeded only by hydropower. This plentiful energy source generated 200 times more electricity than solar energy and 5 times more than wind energy in 1995 (40). If the power produced annually from geothermal energy in the United States had been produced from an average coal-fired plant, there would have been an additional 22 million tons of carbon dioxide, 200,000 tons of sulfur dioxide, 80,000 tons of nitrogen oxides, and 110,000 tons of particulate emissions (whose adverse health effects and increased mortality rates are becoming more widely known) (41–44).

The Geysers geothermal field, located about 120 km north of San Francisco, is the most productive geothermal field in the world. However, power generation there has been decreasing (7–8% per year) owing to declining reservoir pressure since 1987. The problem appears to be that geothermal fluid production is depleting the water content of the reservoir—the natural recharge rate is inadequate to keep pace with the reservoir fluid production rate. In contrast, the thermal energy content of the reservoir rock within the field is far from depleted—only 5% of the thermal energy has been consumed in over 30 years of production. Recent joint research work by the industry and the US DOE has indicated that injection of supplemental water into the reservoir will help arrest the pressure decline and will enable the reservoir to produce power for many more decades (45, 46). However, studies by Pruess & Enedy (47) and others indicate that injection will have to be done with care to avoid adverse interference effects leading to short-circuiting of cooler fluids into nearby production wells. Construction of a 46-km, 51-cm diameter wastewater pipeline from the Lake County Sanitation District to the southeast part of The Geysers field was undertaken in 1995 with completion scheduled for October, 1997 (see 48 for details). This pipeline will bring 29.5 million liters (7.8 million gallons) per day of wastewater to the geothermal field to help maintain reservoir pressure and at the same time dispose of the wastewater in an environmentally advantageous way. Reservoir engineers anticipate that the project will increase generation at The Geysers field by at least 70 MWe. With the successful start of this project, the city of Santa Rosa is planning to undertake a project to determine the feasibility of building a pipeline from their wastewater treatment plants to bring additional water for recharging the central part of The Geysers geothermal field.

INTERNATIONAL GEOTHERMAL POWER INDUSTRY Infrastructure, especially electric power, drives social and economic development. Although developing countries have more than quadrupled their energy usage since 1960, they still face severe energy shortages. Frequent blackouts and brownouts decrease the efficiency of their industrial infrastructure and lead to economic loss. Geothermal power is particularly attractive for developing countries because it can provide uninterruptable base-load power for both on-grid and remote applications. Furthermore, many developing countries are located in areas of active geologic processes—areas that spawn high-grade geothermal resources. The Geothermal Energy Association (49) estimates that as much as 78,000 MWe of geothermal electrical-power generation from hydrothermal resources are available for development from already known resource areas in some 50 developing countries. Realization of this amount of clean power generation would be of immeasurable value to the economies and environments of these countries. Table 3 and Figure 3 show the historical trends for geothermal power generation worldwide with the exception of the period during World War II, when the Larderello field was out of service. Use of geothermal power has been

Table 3 20th Century geothermal electric power production[a]

Year	MWe installed generating capacity	Notes
1902	0.1	Larderello, Italy field starts up
1915	1	
1920	10	
1930	20	
1935	20	
1942	130	
1942–1945	0	World War II curtails production
1950	239	Other countries begin production
1958	362	Wairakei, New Zealand field comes on line
1960	368	Geysers field in California starts production
1965	558	
1970	715	Cerro Prieto, Mexico on line 1973
1975	1314	
1978	1447	
1980	2390	
1982	2882	
1984	4164	
1986	4590	
1988	5420	
1990	5832	
1995	6798	Growth in capacity due largely to Philippines and Indonesia after 1994
2000	9960	Projected

[a]Sources: (10, 13, 14, 54–57). Data are based on surveys and on the compilations of the United Nations, Department of International Economic and Social Affairs, *Energy Statistics Yearbook*, published yearly.

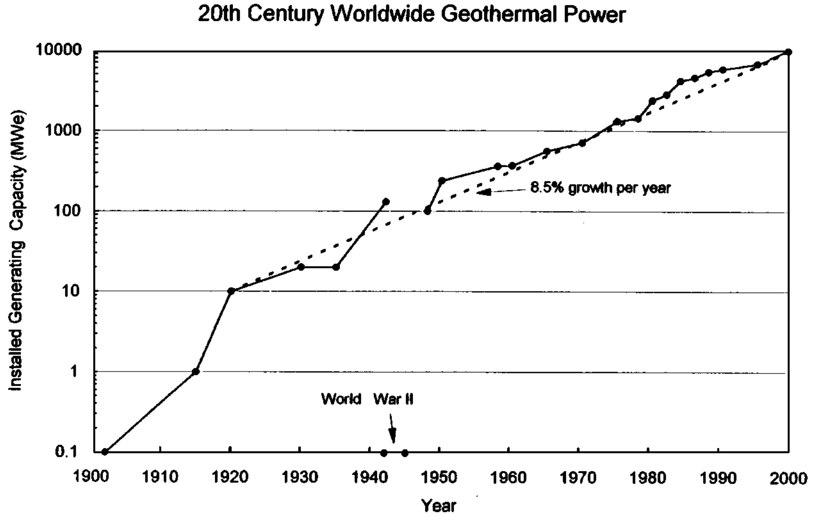


Figure 3 Worldwide geothermal electric power and capacity growth.

exponentially increasing at about 8.5% per year since about 1920, as shown by the dashed line in Figure 3.

The most rapid development of geothermal energy for electrical power production is currently taking place in the Philippines and in Indonesia. The Philippines has now become the world's second largest producer of geothermally generated electricity, growing from a capacity of 890 MWe in 1990, to 1227 MWe in 1995, with an anticipated capacity of 2000 MWe by 1998. Currently, geothermal plants provide power on the islands of Luzon, Leyte, Negros, and Mindanao. Plans for the future include developing new fields, building new plants in collaboration with private industry, installation of topping and bottoming cycles where feasible, and recovery of waste heat for industrial uses (55).

Geothermal capacity has grown rapidly in Indonesia from 145 MWe in 1990, to 310 MWe in 1995, to an anticipated 1100 MWe installed by 2000. The government of Indonesia has recently promulgated a series of regulations that will stimulate the geothermal industry by permitting steam field development and power plant construction by private industry and reducing significantly the tax burden on such projects. A further stimulus is the recent commitment of the World Bank to fund large (20–55 MWe), small (1–20 MWe), and "mini" (35–1000 kWe) power projects at diverse sites in Indonesia (55).

In Japan, electrical power produced from geothermal resources continues to increase with the construction of new plants. At the present time, about 570

MWe of installed capacity have been built, and recent estimates of available (but still undeveloped) geothermal power indicate 5,820 MWe for 30 years for conventional steam generation, with an additional 14,720 MWe for 30 years from binary generation (50).

Although the market for new renewable energy power development in the United States is currently depressed, robust demand in several developing countries is driving aggressive markets for new electrical power using a variety of fuels, including geothermal energy, especially in the Philippines and Indonesia, as discussed above. In many developing countries, electrical power generation and sales are mostly enterprises undertaken exclusively by the government. However, before international investors can or will undertake investment in a country, they must be assured of a reasonable economic return, which depends on the existence of an appropriate business, financial, legal, and regulatory environment in the country (58, 59), along with reasonable assurances that the facilities created by private investment will not later be nationalized without fair compensation and that retroactive laws, taxes, or other unforeseen setbacks will not be put in place. Only then can the quality of a business investment be judged against other opportunities available to the same investor.

Who develops the reservoir? Some developing countries prefer to use state-owned companies to develop their natural resources (petroleum, geothermal energy) and then sell fuel (steam) to the builder and operator of a power plant. The national utility or a direct customer purchases the electricity, and the power-plant developer recovers his investment from the income stream of the electricity sales.

Most American geothermal developers would prefer to develop and operate both the geothermal field and the power plant, selling electricity to a utility or to a private customer. There are good technical and business reasons why this arrangement is preferable. They include the much greater business simplicity of the arrangement, the greater control over the investment, and the ability to coordinate operations to maximize the efficiency of both the reservoir and the power plant together. There is a much greater risk of faulty operation of a geothermal reservoir than there is of faulty operation of a geothermal power plant. Power-plant technology is reasonably straightforward. However, the subsurface details of most geothermal reservoirs are not well understood and are not reliably predictable using today's technology. Experience is a key factor in their successful operation. Poor design of production and injection systems, sometimes a result of trying to save money, has damaged several geothermal reservoirs. No investor is anxious to build a power plant unless he can be assured of a reliable supply of geothermal fluids during the life of the project. Most investors, accordingly, would prefer to have control over this aspect of the project. This preference frequently conflicts with the preference of host countries to retain ownership and control over the resource and to separate reservoir management from power-plant management.

How are power generation resources procured? There are a variety of procurement procedures for acquiring new power-generation resources, including both competitive and non-competitive bidding. Some countries are examining the US Public Utilities Regulatory Policies Act of 1978 (PURPA) and the "Standard Offer" contract arrangements, which implemented this act in California. PURPA created the independent power industry in the United States by mandating purchase of electricity generated by a Qualifying Facility at the utility's avoided cost, which is the cost for the utility to add the same amount of power generation.

In some developing countries, the decision has been made to privatize some or all of the electrical generation, transmission, and distribution facilities. Utilities in the United States and elsewhere have been looking for such acquisitions. Usually there is a requirement that the purchasing entity upgrade the facilities.

ENVIRONMENTAL ATTRIBUTES OF GEOTHERMAL ENERGY

General Impacts

Earlier we discussed the renewable characteristics of geothermal systems as a positive and environmentally sustainable attribute. Other metrics that determine the environmental impacts of a geothermal development include land and water use, noise, seismic and subsidence risks, gaseous emissions, liquid effluents, and solid waste resulting from the development, production, and decommissioning of the geothermal field. In terms of minimizing point-source pollution, many geothermal systems approach emissions- and waste-free operation.

An important feature of land and water use requirements for existing hydrothermal and future advanced systems is that the entire fuel cycle is located at a single site, which eliminates the need to deal with strip mines, gas or oil pipelines, or waste repositories. Water consumption can be controlled by using total reinjection, non-evaporative cooling, and general pressure management in closed-loop recirculating cycles. Because the major elements of a geothermal system are underground, the surface "footprint" of a geothermal plant itself is relatively small. Typical requirements include a building to house the power generating equipment, and land space for wellheads and a pipe distribution system.

When geothermal energy is used to generate electricity, there is always waste heat rejected to the environment. Typically, the largest visible feature of a geothermal power plant is its battery of cooling towers. Thus, the impacts of the waste heat itself on the local ecology and the means used to reject it need to be considered. Fortunately, individual plant sizes are usually limited to 50–100 MWe, resulting in waste heat rates that usually have small local environmental consequences as point sources.

During field development, drilling operations, and plant construction, noise and disruption of normal activities are of concern. After the plant begins operation, noise levels usually are controlled by silencers and other active noise abatement measures. At many sites, the land above developed geothermal reservoirs has remained in service for residential, agricultural, recreational, and industrial uses.

Induced seismicity and subsidence due to geothermal fluid extraction with reservoir pressure changes are possible. However, the magnitude of these environmental concerns is often tempered by the high natural seismic activity levels that are commonplace in most active hydrothermal regions. Typically, high frequencies and densities of very small microseismic events occur within and at the margins of these fields. These actually relieve in situ stresses in a regular fashion and may help mitigate massive fault movements or major earthquakes (11). Monitoring of seismic activity in geothermal areas is commonly employed to verify general behavior and to assess risks. Current data suggest that seismic risks in geothermal developments are very low (10, 11, 13, 15, 16, 53, 57, and 68).

When large volumes of fluid are removed from underground reservoirs, the overburden confining stresses can cause compaction of the rock formation leading to observed subsidence of the land surface. In vapor-dominated fields, stable formations with in situ subhydrostatic pressures are common and subsidence is minimal and rare. However, in liquid-dominated fields with super-hydrostatic fluid pressures, subsidence effects have been observed if replacement fluids are not injected to maintain reservoir pressures (13). Similar effects are observed in oil and gas fields where water injection is routinely used to mitigate subsidence. In a geopressured reservoir, subsidence can also be a problem, as the reservoir itself is supporting a major portion of the lithostatic stress. Here fluid injection will be needed to replace fluids that are extracted to maintain formation pressures and formation stability and production rates. With hot dry rock systems, closed-loop arrangements with total reinjection of fluids are envisioned (see Figure 4), thus both seismic and subsidence risks should be minimal (11).

Because all hydrothermal and geopressured systems contain steam and/or water phases with dissolved gases (CO_2, H_2S, NH_3, etc) and minerals (silicates, carbonates, metal sulfides and sulfates, etc) present in varying concentrations, depending on in situ conditions, there is a possibility of enhanced release rates over those naturally present. Nonetheless, technologies exist to separate and isolate most components in gaseous or liquid streams to control concentrations within regulated guidelines. For example, The Geysers field located in Lake County, California has been able to operate well within California Clean Air Standards, which are currently the strictest in the United States, by using appropriate H_2S abatement techniques. In addition, reinjection of spent brines or condensed vapor streams back into the formation is used to limit emissions and effluents and to keep the reservoir pressurized.

Potential for CO_2 Reduction and Pollution Prevention

For those geothermal systems that employ flashed steam cycles and/or do not use total reinjection of fluids, dissolved carbon dioxide (CO_2) can be released. The range of possible CO_2 emissions from plants utilizing hydrothermal resources in this manner is estimated to be 0.01–0.05 million metric tonnes (MMT) of carbon per quad of energy (10^{15} Btu or 10^{18} J). However, this is considerably less than for fossil-fueled alternatives [coal: 29 MMT/quad; oil: 21 MMT/quad; and natural gas: 15 MMT/quad (6, 60)]. Hydrothermal reservoirs also have very low emission levels of SO_x, no NO_x, and minimal particulates. For closed-loop hot dry rock concepts, no CO_2, NO_x, SO_x, or particulates are emitted.

Clearly there are substantial opportunities for using geothermal energy to reduce greenhouse gas emissions and atmosphere pollution levels by displacing existing or planned fossil-fired electric power generation plants or fossil-fired boilers used for direct heating applications. These stationary systems currently make up about 80% of worldwide total energy demand. The other 20% is in the transportation sector, which also requires a transportable and storable fuel. Having identified vehicle emissions as a major source of local air pollution in mega-cities (61), Mexico City, Los Angeles, and Tokyo have each initiated comprehensive studies to identify the nature and magnitude of the problem and to develop politically viable, cost-effective solutions. In general, government efforts to control exhaust emissions embrace regulatory controls (e.g. limiting the number of vehicles on the road, rationing fuel, and enacting driverless days) and technical advances for pollution abatement (e.g. catalytic converters, electric vehicles, improved fuels, and fuel-cell engines). Providing clean-burning hydrogen (preferably used in fuel cells) has been suggested as an option for pollution abatement. However, the production, distribution, and use of hydrogen must first be shown to be cost effective. Kruger & Fioravanti (62) have suggested a means for geothermal energy to supply hydrogen economically (63).

Electrolytic production currently amounts to less than 1% of the hydrogen market because of the high cost of electricity relative to natural gas for steam reforming. However, when electricity is available as off-peak capacity (64) from either remote or intermittent sources (65), electrolytic hydrogen can be produced competitively. The cost of electrolytic hydrogen can be further reduced using high-temperature electrolysis with efficiencies greater than 80% (66).

Kruger & Fioravanti (62) contend that the capacity of geothermal fields, most efficiently used for base-load electric power, could be increased to above peak-load demand and the integrated excess capacity used to manufacture hydrogen at a competitive level. Case studies of applying geothermal technology to the Mexico City (62) and Tokyo (67) air basins are available.

TOMORROW'S HEAT MINING TECHNOLOGIES

Hot Dry Rock

As introduced previously, the greatest potential source of geothermal energy is contained in hot rock formations to technically accessible depths (currently approximately 10 km) in the earth's crust that do not contain sufficient fluids and/or permeability and porosity to permit heat extraction at commercially viable rates. Figure 4 illustrates the heat mining concept being pursued to stimulate production in low-permeability formations in competent rock by creating an open network of fractures that emulate many features of existing hydrothermal reservoirs. The primary technique for engineering these so-called hot dry rock systems utilizes fluid pressure to open and propagate fractures from wells placed in a region of rock at temperatures ranging typically from 150 to 300°C. The main idea is to enhance natural permeability by opening old and/or creating new fractures and connecting to a set of injection and production wells. Energy would be extracted by circulating pressurized water in a closed loop from the surface plant down one well, through the fracture network where it is heated, and up the second well to return it to the plant. Within the plant, thermal energy could be used directly for residential or process applications or to generate electricity in a power cycle similar to the ones employed for hydrothermal resources. With this closed-loop design, emissions and effluents from HDR systems are practically nonexistent. Of course, the impacts of waste heat rejection, water and land use, and potential seismic risk are still present.

Because HDR systems do not require contained hot fluids or in situ permeability, the HDR resource base is much larger and more widely distributed; practically speaking it is ubiquitous, varying only in grade. Table 1 provides estimates of the HDR resource base for low- and high-grade systems. In general terms, assuming that the rock formation is amenable to stimulation, the grade, in economic terms, is largely specified by the average geothermal gradient, as this will determine drilling depths to reach certain temperature levels. The average baseline gradient for the world is about 25°C/km. This establishes the low-grade HDR resource, one that would have to be exploited if geothermal energy is to be universally available. Hyperthermal areas with gradients in excess of 60°C/km characterize the high-grade end of the resource. For example, in the Western United States, Iceland, and parts of Japan, generally higher heat flows and other desirable geologic conditions have led to large regions with gradients of 60–80°C/km and smaller zones with gradients of 100–200°C/km such as in the Geysers–Clear Lake part of northern California.

The resource estimates for HDR given in Table 1 are orders of magnitude larger than the sum total of all fossil and fissionable resources. Although these estimates refer to the total usable thermal energy content of the geothermal resource that is accessible with current technology, even if only a small fraction can be economically extracted, the impact of HDR as a provider of sustainable emissions-free energy would be far-reaching on a global scale. In fact, it is this great potential of universal heat mining that has encouraged many to advocate pursuing HDR with both major national and international R&D efforts.

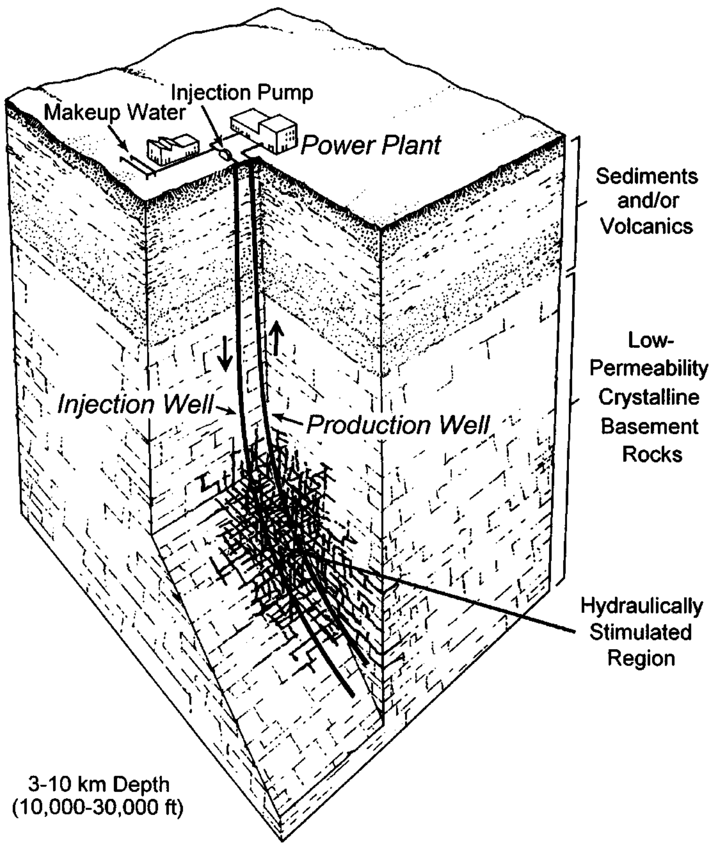


Figure 4 Hot dry rock (HDR) concept for low-permeability formations.

For the past 24 years, the Los Alamos National Laboratory, with the sponsorship of the US DOE, has led the research effort of developing HDR technology (11, 15, 60, 68). Most of the field work has been concentrated at the Fenton Hill site in north central New Mexico, which is in a high-gradient region on the western flank of an extinct volcano known as the Valles Caldera. For a period during the 1980s, the Federal Republic of Germany and the Government of Japan supported a portion of the US effort at Fenton Hill under a collaborative agreement within the IEA. The Japanese, as reported by Sato & Ishibashi (69) and Sato et al (**?**), are now developing HDR technology on their own, and the Germans have joined forces with other members of the European Economic Community (EC) to pursue HDR with modeling and field work at several sites in Europe (e.g. at Soultz). Kappelmeyer et al (71) and Duchane (15) described European R&D on HDR. From about 1974 until 1992, the British were carrying out extensive field tests at the Rosemanowes site in Cornwall under sponsorship of the UK Energy Technology Support Unit at Harwell (for details see 72–74). More recently they too have joined the EC project in Europe and have suspended operations at Rosemanowes. There are a few other important R&D activities in other countries, most notably Russia (75).

These field programs have made substantial progress in developing methods to drill, stimulate, and characterize the structure and performance of HDR reservoirs in a range of different geologic settings. Most of the field work has focused on creating HDR reservoirs in low-permeability formations that have little fluid content (i.e. low porosity) where the dominant features consist of sealed natural fractures or joints contained in otherwise competent rock of extremely low matrix permeability (10^3–10^7 times less permeable than a typical oil reservoir). In these cases, hydraulic fracturing methods employing the injection of pressurized water with or without special rheological additives have been used to create an open labyrinth of connected fractures. In other efforts, where open joint systems containing significant amounts of water or steam exist naturally (so-called hot wet rock), field development work concentrates on reservoir characterization to insure proper well placement to optimize the distribution of fluid flowing in the fractured system.

The US and Japanese experiments at Fenton Hill and at Hijiori, respectively, have clearly demonstrated that conventional drilling methods can be adapted for the harsh environments encountered in reaching zones of rock from 250 to 350°C, which are hot enough to be suitable for commercial power production. Field testing has also verified that hydraulic pressurization methods can create permanently open networks of fractures in very large volumes of rock. Experiments at Fenton Hill and Rosemanowes, for example, have extended open, connected fracture networks to kilometer dimensions, producing systems that are large enough for long-term commercial production. Techniques using chemical (especially inert) tracers, active and passive acoustic methods, and other geophysical logging techniques have been used to map out the geometric features of HDR reservoir systems to validate thermal hydraulic models of heat extraction performance.

While all of this work has led to demonstration of the technical feasibility of the HDR concept, none of the testing to date has demonstrated all the performance characteristics required for a commercial-sized system. Two major issues remain as constraints on global commercialization: 1. the demonstration of sufficient reservoir productivity with low-impedance fracture systems of sufficient size and thermal lifetime to maintain economic fluid production rates of 50–100 kg s^{-1} per well pair at wellhead temperatures above 150°C, and 2. the relatively high cost of drilling wells in hard rock. In certain geologic situations, controlling water losses is important, as it can have both negative economic and environmental impacts.

A key economic parameter is the cost of producing a unit of fluid at a specified temperature. This can be expressed in dollars per kg/s of fluid produced or in dollars per kW of thermal power. High fluid production temperatures and large sustained reservoir flow rates per well pair and lower individual well drilling costs reduce the overall cost of HDR energy. On the other hand, higher flow rates through the reservoir lead to increased pumping power losses and accelerated rates of thermal drawdown, which lead to higher costs. The economic choice is to balance these effects.

This balance can be illustrated quantitatively by dividing the total installed cost of a geothermal development into major components associated with the field itself and its reservoir and with the power plant that converts the thermal energy into electricity. In mathematical terms the total capital cost Φ is

$$\Phi = \Phi_{\text{geofluid}} + \Phi_{\text{power plant}}, \tag{1.}$$

where Φ_{geofluid} is the total field/reservoir development costs including those for geophysical exploration, well drilling, reservoir stimulation, and fluid transmission, collection, and distribution; and $\Phi_{\text{power plant}}$ is the installed capital costs of power conversion and electrical generation equipment and switch gear for connecting to the grid. The geofluid component can be represented roughly as

$$\Phi_{\text{geofluid}} = 2n_{\text{w}}A(\Phi_{\text{well}}), \tag{2.}$$

where n_{w} is the number of production wells (the factor of 2 accounts for an equal number of reinjection wells), Φ_{well} is the individual completed well cost in dollars per well and A is an empirical constant that includes costs for rig mobilization and demobilization, reservoir stimulation, and the geofluid collection and distribution system to the power plant. Φ_{well}, in turn, is expressed

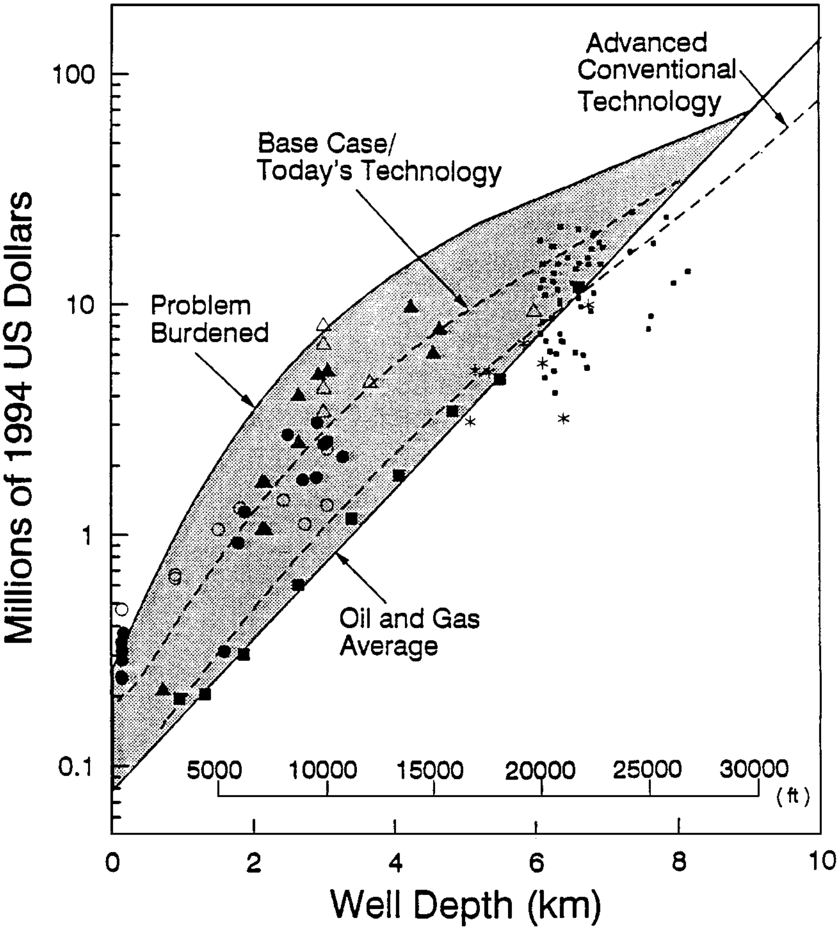


Figure 5 Drilling costs for completed wells ranging in diameter from 30–40 cm (12–16 in.). *Filled triangles*: HDR Actual; *filled circles*: hydrothermal actual; *small filled squares*: JAS ultra deep; *stars*: SPE oil and gas; *open triangles*: HDR predicted; *open circles*: hydrothermal predicted; *large filled squares*: JAS correlation.

as an exponential in depth as depicted by a straight line in the shaded region of Figure 5,

$$\Phi_{\text{well}} = C\exp(Dz), \qquad 3.$$

where z is the reservoir/well depth in meters $= (T_{\text{gf}}\ (t = 0) - T_{\text{surface}})/\nabla T$, T_{gf} $(t = 0)$ is the initial reservoir fluid production temperature in K, T_{surface} is the average ambient surface temperature $(z = 0)$ in K, ∇T is the average geothermal temperature gradient in K (or $^\circ$C) per meter ($^\circ$C/m) and C and D are constants fit to the data presented in Figure 5. The number of wells, n_w, is given by,

$$n_w = \frac{P}{\eta_u m_w \Delta B}, \tag{4.}$$

where P is the power capacity of the plant in kW, η_u is the utilization efficiency or the fraction of thermodynamically limited power, typically 0.50–0.60, m_w is the geofluid mass flow rate in kg/s, and ΔB is the thermodynamic availability or maximum work producing potential of the geofluid in kJ/kg.

For a liquid-phase geofluid,

$$\Delta B \approx \langle C_p \rangle [T_{gf}(t) - T_0 - T_0 \ln(T_{gf}(t)/T_0)], \tag{5.}$$

where $\langle C_p \rangle$ is the mean heat capacity (of the geofluid) in kJ/kg, and T_0 is the minimum thermal sink temperature in K. Plant capital costs typically decline as T_{gf} increases, owing to improved cycle efficiency and lower heat transfer area requirements. Empirically, we have represented this decline as a linear function,

$$\Phi_{\text{power plant}} = \Phi^\circ_{\text{power plant}} - E T_{gf} \tag{6.}$$

applicable only for $150^\circ\text{C} \leq T_{gf} \leq 300^\circ\text{C}$ where $\Phi^\circ_{\text{power plant}}$, and E are empirical constants (76–78).

Ideally, to minimize costs, we need to find a minimum in Φ from Equation 1 for certain choices of m_w and T_{gf}. Unfortunately, for a given-sized reservoir, these variables are connected in a nonlinear fashion and lead to certain economic tradeoffs. In real reservoirs, some decline in productivity is anticipated. This usually is expressed in terms of a reduction in T_{gf} over time. To optimally extract energy from a HDR reservoir one must inject fluid at a sufficiently high rate (m_w) to cause some thermal drawdown. But as T_{gf} decreases, so does ΔB from Equation 5, and consequently n_w (Equation 4) and Φ_{geofluid} (Equation 2) both tend to increase. To partly compensate for finite thermal drawdown, deeper, more costly wells (Equation 3) can be drilled. Hence, to reach an optimum for a given HDR resource, defined generically by specifying both ∇T and reservoir size, a tradeoff exists between pumping more fluid (higher m_w) and drilling deeper (larger z). With reasonable values for equipment and drilling costs and acceptable levels of reservoir performance, initial reservoir temperatures of 250–300°C are favored when $\nabla T > 50$ K (or $^\circ$C)/km, whereas somewhat lower temperatures are better for lower ∇Ts.

Given these characteristics, how does HDR fit into the global energy picture? As we move into the next century, we should be exploring means of meeting our future energy needs without increasing fossil fuel use. Key criteria for any new energy technology are that it should be relatively simple to implement and safe to operate, and have reasonable costs, high availability, and low environmental impact over its life cycle from "cradle to grave." In addition, the "scale" of the technology should be compatible with anticipated demand, and the resource should be adequately distributed to meet both base-load electricity and other distributed primary energy needs. Although hot dry rock seems to meet all these criteria as well as or better than other alternatives, it has not been pursued as vigorously as other technologies.

Fission, fusion, and solar photovoltaics are examples of alternative energy sources that have received substantial government support not only because they are potentially viable replacements for fossil fuels but also because they each have a relatively large group of advocates. Hot dry rock and geothermal in general have much smaller constituencies, and as a result their positive attributes and the current state of development of geothermal energy systems are not as widely known to the public.

Commercialization of any new energy system depends critically on how well it competes with existing energy supplies. As with any developing technology, competitiveness and risk have real and perceived elements. HDR is unique in that certain elements, such as the surface power plants, have relatively low cost and low performance uncertainty, as they consist of commercially viable "off the shelf" components (pumps, heat exchangers, turbines, etc). On the other hand, the underground reservoir systems consisting of the wellbore-fracture network carry much higher risk, partly because the technology is not yet fully mature and partly because drilling and reservoir stimulation are perceived to be very speculative because of natural parallels that are drawn to oil and gas production. One must remember that exploration and production uncertainties for a HDR reservoir are intrinsically lower than for a petroleum reservoir in general or a high-grade hydrothermal system specifically. In principle, all we require is sufficiently hot rock at accessible depths that is amenable to stimulation to create an open, connected fracture system.

The main technical obstacles for HDR are centered on formation and connection of the fractured network to the injection and production well system in order to provide low impedance access to sufficiently large rock areas and volumes with acceptable water losses. For example, for an average geothermal gradient resource of 60°C/km, production flow rates of about 40–75 kg s^{-1} with water losses less than 5% and thermal drawdown rates of about 2% per year or less from an initial temperature of 250–300°C are required to achieve break-even electricity prices of \$0.06–\$0.08 per kWh (in 1996 dollars) (11, 76, 78, 79). These estimates include the amortized capital costs of drilling and stimulating the wells and building the power plant, along with operating and maintenance costs of about \$0.03–\$0.04 per kWh.

Economic assessment studies conducted at Los Alamos, EPRI, and elsewhere have been dissected to reformulate a generalized economic model for

HDR with revised cost components (76, 77). The main results of this comparative study are shown in Figures 5 and 6 where drilling costs and break-even electricity prices are presented. Figure 5 shows that the cost of individual wells is exponentially dependent on depth in general and that geothermal wells, on average, are two to three times more expensive than oil or gas wells drilled to the same depth. Figure 6 shows the strong dependence of projected break-even price on average gradient, which reflects the grade of a HDR reservoir. As gradients increase, the drilling cost component decreases relative to the surface plant cost. The bandwidth shown in Figure 6 illustrates the effect of technological improvements on costs. In order to make HDR geothermal energy commercially competitive for low-grade resources with gradients ranging from 20 to 30°C/km, revolutionary changes in the way wells are drilled are required to lower costs substantially.

All of these economic assessments for HDR assume reservoir productivities comparable to commercial hydrothermal systems (76–80). While the field testing to date has not yet reached these productivity levels, the key problem is lowering flow impedance, not creating reservoirs of sufficient size, which has already been achieved in tests at Fenton Hill and Rosemanowes. The hydraulic connectivity between the injection and production wells and the fractured reservoir needs to be improved to reduce pumping losses due to high flow impedances (Fenton Hill) or to lower water loss rates (Rosemanowes).

Critics of HDR technology have argued that with over $180 million invested during the past 24 years in the United States alone, development toward a commercially viable system has been too slow. However, this criticism needs to be weighed against the R&D investments made in other non-fossil, "backstop" energy technologies. For example, the total US investment in HDR in 24 years is less than half of what we are currently spending *annually* on fission, fusion, or solar energy technologies.

Realistically, however, the future of HDR technology development in the United States, at least in the decade ahead is dependent upon the status of reservoir testing at the Fenton Hill experimental site in northern New Mexico. Unfortunately, with a decreasing federal budget for advanced energy research within the US DOE, funding for further testing at Fenton Hill or to develop the potentially large HDR resource, in general, has become grossly inadequate. Regrettably, at the time of this writing, the Fenton Hill site is in the process of being decommissioned. Now is a very appropriate time to reflect on what has been achieved in field testing in light of remaining technical and economic barriers. A more farsighted perspective in considering these issues is needed, and the roles of government and industry require articulation to promote further development of HDR worldwide; for example, what level of funding from

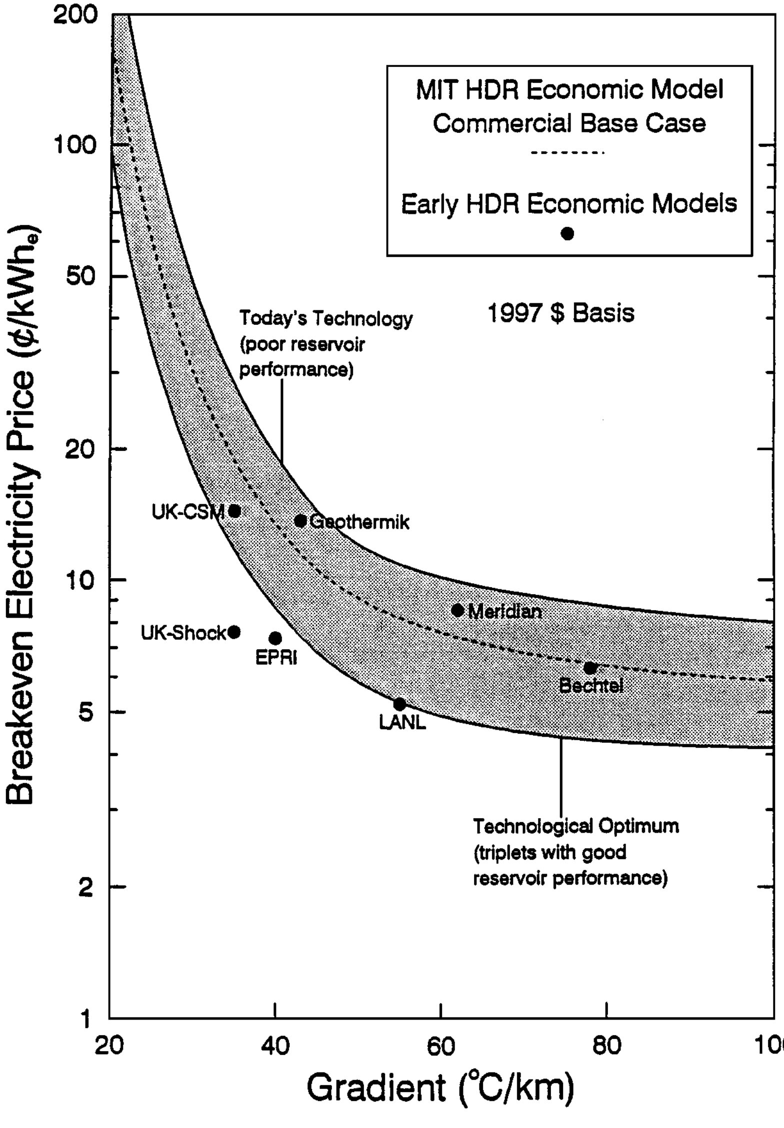


Figure 6 Economic cost projections for heat mining: break-even busbar electricity price versus average geothermal gradient (adapted and updated from References 76, 77) using standard inflation indicia for plant and drilling costs.

public and private sources should be allocated to HDR research and development? The potential of HDR as a major non-fossil component of the US and world energy supplies in the next century should be carefully compared with that of the other options of similar magnitude, such as fission, fusion, and solar.

Two important criteria for allocating government funds for developing a particular energy type are 1. the potential magnitude and environmental sustainability of the resource and 2. the total projected R&D investment and the time required to develop the technology. Adherence to such a policy when fossil energy prices are low will require a continuing strong role for the government during the next phase of HDR development. During this phase, industry should be involved in cost-shared construction and testing of several HDR demonstration systems at geologically different sites. This would facilitate technology transfer to the private sector and reduce real and perceived risks that currently limit large-scale HDR commercialization.

Magma Energy

Recovery of energy from very hot magma bodies is a goal worth pursuing because it would open up possibilities for both high-efficiency electricity generation and high-temperature chemical or metallurgical processing that is not possible with any other geothermal resource. Magma bodies represent localized regions of immensely concentrated thermal energy consisting of molten or near-molten material at temperatures in excess of 650°C. To be classified as a geothermal resource, they must be located in the earth's crust at depths accessible with conventional drilling methods—currently about 10 km (30,000 ft). In rare cases, magma bodies are found at the surface such as at or near the sites of active volcanoes. The United States, the former USSR, and Japan have focused advanced research and development on engineering technologies for extracting heat. In particular, scientists at Sandia National Laboratories during the 1980s experimented in the field with different methods at two sites in the United States. One site is the Kilauea Iki lava lake in Hawaii where actual heat extraction tests were conducted; the other is in California at the Long Valley caldera where exploratory drilling was carried out (81–83). Other potential sites in the United States include the Valles Caldera in north central New Mexico and 12 active volcanoes of the Cascade range in the Pacific Northwest.

Use of magma for carrying out high-temperature chemical reactions to produce transportable fuels such as methane and hydrogen has been proposed by Gerlach (82). One idea, particularly suited for magmas rich in iron oxides, is to carry out a thermochemical reaction of ferrous oxide (FeO) and water to produce ferric oxide (Fe_2O_3) and hydrogen. Another concept is that biomass would be gasified to produce first methane (CH_4) at moderate temperatures and then synthesis gas, a mixture of hydrogen and carbon monoxide (CO), by further reaction of CH_4 with CO_2 at higher temperatures.

Modeling efforts at Sandia based on preliminary field testing in Hawaii suggest that a single well drilled into a magma body at 1000°C could generate 30 MWe (15). Another more recent estimate of power generation costs by Crewdson et al (84) for Long Valley predicts that commercially competitive busbar costs of \$0.056 per kWh may be possible. Although these are estimates for high-grade magma resources located near the surface, drilling and its associated costs may not be the limiting factor. Of more importance is engineering a heat extraction system that will work for extended periods at high rates of thermal power production. Critical issues include maintaining high heat-transfer rates when solidification of magma occurs during extraction, finding economic materials that can withstand the temperatures and chemistry of molten rock (including drilling hardware, well casing and cements, and tubular goods involved with heat extraction), and finding ways to insure that the reservoir itself remains stable and safe during drilling and production. Meeting these challenges requires an active R&D effort, which was underway under US DOE sponsorship until recently. Unfortunately, current R&D levels for magma are now at a very low level, and it is too early in the development of this resource to provide reasonable projections of costs for providing electricity or process heat.

Geopressured Energy

Geopressured-geothermal brines are hot pressurized waters that contain dissolved methane and lie under the earth's crust at depths ranging from 12,000 to more than 20,000 ft (3,600–6,000 m). Brine temperatures range from 50 to 260°C (120–500°F); pressures from 560 to 1380 bar (7,500–20,000 pounds per square inch); salinities from 10,000 to 300,000 ppm; and gas contents from 0.65 to 2.85 SCM {standard m^3 [23–100 SCF (standard cubic feet)]} per barrel of brine. Geopressured resources occur worldwide. In North America, such resources are found in Alaska, in the Rocky Mountain regions, in California, and along the coast of the Gulf of Mexico (85, 86). The northern Gulf of Mexico sedimentary basin contains a deep sequence of relatively permeable sandstone layers interbedded with relatively impermeable shales (87). Both formations are relatively porous and contain large quantities of hot brine with dissolved methane under abnormally high pressures.

Geopressured resources possess a unique advantage: They embrace three forms of energy—thermal (hot brine), chemical (natural gas), and mechanical (hydraulic). It is possible to exploit each form singly or in combination to satisfy a variety of energy needs. In 1974, the federal government established a program to determine whether the geopressured aquifers along the Gulf Coast could be exploited technically and economically as a major source of domestic energy. The US Geological Survey (USGS) has estimated that the northern Gulf of Mexico basin contains approximately 170,000 quads of energy (107,000 quads thermal at temperatures greater than 100°C, 63,000 quads from combustion of the dissolved natural gas) (88, 89). By comparison, US total energy consumption is approximately 85 quads per year.

The DOE initiated a major geopressured-geothermal R&D program organized into three groups responsible for well operations, geosciences and engineering support, and energy conversion, respectively. The well-operations group gathered and analyzed data from two types of wells drilled into geopressured aquifers: "wells-of-opportunity" (unproductive oil or gas wells donated by industry) and "design wells" (those wells drilled specifically for scientific study). High-flow-rate well tests and pressure-buildup tests were conducted to gain knowledge of reservoir production performance, to determine reservoir drive mechanisms, and to investigate the feasibility of long-term brine production at high flow rates (87, 90). The geosciences and engineering support group focused on analyzing well data to understand the performance of geopressured reservoirs under long-term high-volume production and to identify the mechanisms driving the production of geopressured fluids, enabling the prediction of long-term production based on short-term tests. The energy conversion group focused on finding economical ways to use the three primary forms of geopressured energy. The thermal energy can be used directly or converted to electricity; the gas can be sold, converted to methanol, or converted to electricity; and the high pressures can be converted to electricity using a hydraulic turbine. Hybrid systems were investigated that use several of these technologies in the same system with significantly increased efficiencies (91).

The geopressured R&D program successfully (85, 87, 92, 93) identified the geopressured fairways in the onshore Gulf Coast areas of Texas and Louisiana with an estimated 5700 quads of methane in the sandstone reservoirs. In addition, the program established the feasibility of locating geopressured reservoirs using geophysical logs from previously drilled petroleum wells and active seismic data, and the feasibility of adapting US petroleum industry drilling and production technology to the production of geopressured brines, proving it possible to extract the gas from the brine by simple and economical gravity separation techniques. The program also verified that geopressured pressure gradients range to more than twice the normal hydrostatic gradient, over temperatures ranging from 50 to 260°C. Further, the solubility of methane in geopressured brines was shown to decrease with increasing salinity. New technologies for assessing and using the resource were demonstrated, establishing that brines flow naturally at rates of up to 40,000 barrels per day from a single well (where 1 barrel = 42 gallons US) and can be reinjected into shallow aquifers without affecting the surface and near-surface water and without causing subsidence or associated seismic activity.

The research program also characterized two large sandstone aquifers, each estimated to contain in excess of several billion barrels of brine. Technology was developed for successfully controlling the formation of calcium carbonate scale in wellbores using phosphonate scale inhibitors. Electronic data bases were created using data from thousands of geophysical logs in Gulf Coast oil and gas wells and technical bibliographic material at the University of Texas, Louisiana State University, and the USGS facility at Bay St. Louis, Mississippi.

An important element of the geopressured program was the successful demonstration of a hybrid power system at Pleasant Bayou in Brazoria County, Texas, which supplied about 3500 MWe-hr to the Houston Power & Light Company's grid over a one-year period. In a collaborative effort sponsored by the DOE and EPRI, the Ben Holt Company designed and constructed a 1-MWe hybrid cycle system in which gas was burned in an engine to generate electricity directly. Exhaust heat from the engine was then combined with heat from the brine to generate additional electricity in a binary cycle. Heat from the gas-engine was available at high temperature, improving markedly the efficiency of the binary portion of the hybrid cycle. Campbell & Hattar (94) report that hybrid cycles can yield 30% more power than stand-alone geothermal and fossil fuel power plants operating on the same resources.

The Idaho National Engineering Laboratory initiated a geopressured technology transfer program, including the establishment of the Industrial Consortium for the Utilization of the Geopressured-Geothermal Resources (95). Feasibility studies were conducted, covering many applications: agriculture, aquaculture, desalination, enhanced oil recovery, methanol conversion, and unique applications such as supercritical fluid processing of organic wastes (96). Supercritical water oxidation is the combustion of organic matter in water with oxygen at temperatures and pressures above the critical point of water (374°C and 221 bar), conditions readily achievable with geopressured fluids. The solvent properties of supercritical water change so that nonpolar organic compounds become soluble and salts become insoluble. With the addition of an oxidant (air or oxygen), organic materials can be oxidized into carbon dioxide and water very rapidly, usually within a minute (95, 96). Use of geopressured fluids has been proposed for cleaning up municipal sewage and hazardous organic chemicals such as polychlorinated biphenyls (97).

CRITICAL ISSUES AFFECTING GROWTH OF GEOTHERMAL POWER

Technology Transfer to Industry

Since the early 1970s, several billion dollars have been invested in geothermal R&D by the geothermal industry, by utilities and consortia such as the

Electric Power Research Institute (EPRI), and by the US government. Applied research is valuable, however, only in proportion to how widely it is disseminated and introduced into the marketplace. Technology transfer is the process by which innovations are successfully diffused commercially. As stated by Deutch (98), "the rationale and the justification for government-sponsored non-military R&D are based on the premise of eventual commercial applications of research results." To accelerate the flow of R&D to the marketplace, the DOE sponsored several technology transfer conferences, a number of articles (99, 100), the definitive text called *Moving R&D to the Marketplace: A Guidebook for Technology Transfer Managers* (101), and a comprehensive technology transfer program consisting of several discrete elements based on the Technology Delivery System (TDS) concept (100).

The first element (Cooperative R&D) was designed to assure meaningful problems were addressed and industry was involved in research ab initio. As an example, in 1977, Sandia National Laboratories joined with the General Electric Company and various drill bit manufacturers in the application of man-made diamonds to geothermal drilling, culminating in the patented Stratapax drillbit with bit lives and penetration rates two to three times those of roller bits in the shales and sandstones in the Imperial Valley (102).

The second element (Financial Assistance) was designed to inform the financial community of the investment opportunities in the infant geothermal industry and to help reduce the risks perceived by bankers and financiers. The Geothermal Loan Guaranty Program was created by Congress in 1974 to assist in overcoming the financing risk barriers to the development and operation of geothermal projects. A notable success was the Ormat East Mesa Project in the Imperial Valley of California, where the $50 million guaranteed loan was prepaid in full one year after the loan was funded. This project was subsequently expanded with private sector financing from its initial 24 MWe in 1986 to 60 MWe by 1989, helping to establish the technical and economic feasibility of large-scale modular binary power plants (103).

A third element (Joint Ventures) focused on accelerating the establishment of commercially viable technology by cost-sharing the high-cost, high-risk front-end activities. Five programs were initiated: (*a*) the industry-coupled drilling program, (*b*) the state-coupled resource assessment program, (*c*) the Geothermal Loop Experiment Facility (GLEF), (*d*) the user-coupled confirmation drilling program, and (*e*) the program opportunity notice (PON) program. Research at the GLEF was instrumental in establishing dual flash conversion technology needed to exploit high-temperature, high-salinity brines, contributing to the development of the crystalizer-clarifier, a technology for the control of well-scaling silicates. The transfer of this technology made many high-salinity geothermal reservoirs, such as those in the Salton Sea area in California, available for commercial development (104).

The fourth element (Technical Assistance) was designed to help overcome the reluctance of potential users (especially small and technically unsophisticated firms) to take on the risk of tackling a new technology. For example, the Oregon Institute of Technology Geothermal Heat Center was established to provide technical assistance to developers of direct use projects. This assistance led to the successful completion of the nation's largest (over 75 billion Btus per year) geothermal district heating system located in San Bernardino, California.

The fifth element (Education-Training) was established to educate the public and the broad geothermal community (developers, researchers, bankers, legal experts, government officials, regulators, educators) about the new developments and new trends. DOE cooperated with EPRI, the USGS, universities, and industry organizations in sponsoring conferences, in publishing reports, in providing topical training courses, and in producing (through the Geothermal Education Office) videotapes and training materials for teachers and the general public.

The sixth element (International Cooperation) was initiated to provide US industry with knowledge of recent innovations and best practices in other countries having intensive geothermal development (Italy, Mexico, Iceland, New Zealand, and Japan). For example, a series of exchange visits was set up between US developers and the Italian Ente Nazionale per l'Energia Elettrica (ENEL), which was helpful in guiding injection experiments at The Geysers by learning of successful load-following and reinjection experiments at Larderello. This research assisted in the development of the Southeast Geysers Effluent Pipeline project, the world's first wastewater-to-electricity system, representing a unique example of technology transfer. Based on the success of the reinjection research and on the need for Lake County to find an economically and environmentally acceptable way to dispose of wastewater effluents, a project was established to carry Lake County's wastewater effluents through a 46-km pipeline for injection in The Geysers steam field, producing up to 70 MWe of generating capacity (105).

A brief (but by no means comprehensive) list of successful technology transfer efforts includes hard-rock drill bits, high-temperature drilling muds, long-life rotary head seals, lost-circulation controls, high-temperature cements, chemical tracers and tracer techniques, water injection techniques, high-temperature electronics, reservoir models, seismic technology, polymer concrete, microbial processes for bioremediation, major binary cycle improvements, reservoir stimulation processes, rolling float meters, CO_2-resistant cements, brine chemistry computer models, borehole fluid samplers, electronic logging tools, and geothermal heat pumps (104, 106, 107).

Competing in Today's Energy Markets

Geothermal energy is already commercially competitive in many locations worldwide where high-grade hydrothermal resources are found. By the turn of the century, over 10,000 MWe of generating capacity from geothermal resources is likely. Even more significant is the fact that subsidy-free geothermal power is frequently the least costly option for developing countries such as Indonesia, the Philippines, and many countries in Central America. This is quite remarkable given the low cost of oil and gas on international markets and the capital-intensive nature of a geothermal development where all the "fuel" costs are embedded in the initial investment in drilling wells and connecting the fluid production and reinjection piping.

In the United States, the situation regarding geothermal development is more complex, as many regions do not see an immediate need for additional generating capacity. In addition, the United States is currently in the middle of a massive restructuring, at both the federal and state levels, of its electric utilities in the face of national deregulation. Deregulation will include the breakup of the vertically integrated utilities that now constitute monopolies controlled primarily by state regulation. Generation, transmission, and distribution functions will be separated in an effort to increase competition in each area and lower electricity prices to consumers without disrupting the excellent electrical-energy services Americans enjoy. As a result, many utilities will opt to sell their generating capacity to become transmission companies (transcos) or distribution companies (distcos). Generation companies (gencos) will comprise companies spun off from utilities, large independent power producers (IPPs) such as Enron, and the myriad small IPPs currently operating under the Public Utilities Regulatory Policy Act of 1978 (PURPA), which created a market for renewable energy options such as geothermal energy. Gencos may possibly sell their power into a pool, from which distcos would make purchases on a long-term or a spot-market basis (or, more likely, a mixture of the two), and the transcos would wheel the power to the distcos at an agreed transmission rate.

In order to preserve the benefits of clean, renewable energy supplies already in place, as well as to create a nourishing environment for further development, both federal and state law-makers are considering several options. One option is to require a specified amount of the overall electricity fuel mix to be renewable energy, such as geothermal energy—the so-called renewable-energy portfolio standard (RPS). The requirement could be applied at either the distco or the power-pool level. If the RPS percentage were to rise with time, such an option would steadily increase the amount of renewable electricity in the supply, ensuring a growth environment for geothermal energy. Another option, perhaps in addition to the RPS, would be to allow and encourage distcos to market a certain amount of their power as "green power," derived from clean sources, and offer such power to their customers at a marginally higher price. Such issues are being discussed in Congress and state legislatures as this review goes to press, and we can anticipate that several years will be required before all aspects of deregulating and restructuring the electricity industry are ironed out. This is both good and bad for geothermal development—good because this trend decentralizes utility decision making and thereby provides more choices; bad because geothermal electricity is very capital intensive and more risky than options using low-cost fossil fuel. For example, it is very hard for renewable energy to compete with a 10–50-MWe gas-fired combined cycle cogeneration plant with a long-term contract for purchasing inexpensive natural gas. Table 4 summarizes estimates for baseload electricity and process heat for fossil, nuclear, and a range of hydrothermal resources.

For the advanced technologies—hot dry rock, magma, and geopressured—the competition is even tougher, as risk factors will initially be higher for investors. Higher risks will be partially offset for HDR systems by the increased flexibility in locating the system near a load center and the fact that in situ fluids and high formation permeability are not required. Cost estimates for HDR are tabulated in Table 4. Economic projections for HDR or for any pre-commercial technology must be considered somewhat speculative given the assumptions made regarding reservoir performance. For HDR specifically, we have divided the range into high- and low-grade resources. Both cases are assumed to meet baseline reservoir productivity and other performance parameters, including mass flows per well pair of about 75 kg s^{-1} (to generate 10 MWe) effective heat transfer volumes, and areas sufficient to support 10 years of production with 20% thermal drawdown (fractional fluid temperature decline in the production well) or less, flow impedances (resistance to fluid flow) less than 0.1 GPa s/m^3 (an overall impedance of 1 GPa s/m^3 or less is a reasonable goal for a commercial HDR system), and water consumption rates less than 5% of the injected flow (11, 77–80). These baseline values are probably achievable with active R&D programs, as they more or less replicate the productivity levels already achieved for commercial liquid-dominated hydrothermal systems.

As one might expect, high-grade hydrothermal resources are competitive right now for electric power generation, and high-grade HDR resources would be competitive in some fraction of today's energy markets. But the low-grade resources of either will require higher prices for fossil fuels or lower development costs before they can compete. Of course there are other forces—environmental, health-related, security-related, and general sustainable development concerns—that could create a different economic situation.

Table 4 Estimated busbar generating and heat supply costs for new baseload capacity[a]

Electricity

Resource type	Installed and annual plant cost ($/kW)	Installed and annual plant cost (¢/kWh)	O&M costs (¢/kWh)	Annualized well drilling or fuel cost (¢/kWh)	Total breakeven busbar price (¢/kWh)
Oil[b]	800	2.0	0.3	1.7–3.4 ($10–20/bbl)	4.0–5.7
Coal	1200	3.0	0.3	0.6–4.0 ($15–100/ton)	3.9–7.3
Gas[b]	600	1.5	0.3	0.8–2.3 ($1–3/MBtu)	2.6–4.1
Nuclear[c]	3200	7.8	0.4	1.0	9.2
Hydrothermal					
high-grade	1000–1500	2.4–3.6	0.3	2–3	4.7–6.9
low-grade	2000–2500	5.1–6.3	0.4	4–10	9.5–16.7
Hot dry rock					
high-grade (>60°C/km)	1000–1500	2.4–3.6	0.3	3–4	5.7–7.9
low-grade (≈30°C/km)	2000–2500	5.1–6.3	0.4	20	25.5–26.7

Heat Supply

Resource type	Annualized plant capital cost[e] ($/MBtu)	Fuel cost[f] ($/MBtu)	Annualized heat distribution cost[g] ($/MBtu)	Total breakeven price ($/MBtu)
Oil	0.50	2.2–4.4 ($10–20/bbl)	1.5	4.2–6.4
Coal	0.70	0.8–5.0 ($15–100/ton)	1.5	3.0–7.2
Gas	0.50	1–3	1.5	3.0–5.0
Nuclear	5	0.8	2.0	7.8
Hydrothermal[d]				
high-grade	—	2.0	2.5	4.5
low-grade	—	1.6	2.0	3.6
Hot dry rock[d]				
high-grade (>60°C/km)	—	2.5	2.5	5.0
low-grade (≈30°C/km)	—	4.5	2.0	6.5

[a]Values are given in 1996 US dollars. Sources: (11, 14, 56, 60, 76–80).
[b]Combined cycle plant assumed for oil and gas.
[c]Nuclear fuel estimate. Includes allowance for decommissioning and waste handling, treatment, and storage; fission plants only.
[d]Fuel cost includes all heat exchange equipment and drilling costs.
[e]Annual cost based on 17% fixed charge rate, 80% load factor for 50 MW (e or t) plant.
[f]1 MBTU $= 10^6$ BTU $= 1.055 \times 10^9$ J.
[g]Heat supplied at 150°C as steam or pressurized hot water, not cogenerated.

Government Intervention Because of Positive Environmental Attributes

The development of a National Energy Strategy (NES) was initiated in 1989 to achieve a balance among the increasing need for energy at reasonable prices; the commitment to a safer, healthier environment; and the determination to maintain a strong, growing economy (108). The NES was incorporated into the National Energy Security Act of 1992, providing a broad integration of environmental and economic policy with energy policy (109). That same year, world leaders from 200 countries came together in Rio de Janeiro to confront global environmental problems (110). At the Earth Summit, the United States joined in signing The Framework Convention on Climate Change. The stated objective was to achieve "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (110).

In 1993, a Climate Change Action Plan was prepared with the objective of returning US greenhouse gas emissions to 1990 levels by the year 2000. These emissions were projected to grow by 7% by 2000 without the Action Plan, from 1462 million metric tons of carbon equivalent (MMTCE) to 1568 MMTCE. Carbon dioxide from fossil energy use is the largest contributor; in 1990, US carbon dioxide emissions alone were 1367 MMTCE (111).

Under the Action Plan, the Department of Energy formed collaborative programs with private industry to accelerate market acceptance of renewable technologies and to conduct industry cost-shared demonstrations. A consortium of geothermal developers and utilities was established to cost-share drilling and exploration programs to expand geothermal reserves.

A Geothermal Heat Pump Consortium was formed in 1994 (29) to accelerate the development and rapid commercialization of geothermal heat pumps. The consortium sponsors research to reduce installation costs for the employment of subsurface heat-exchange loops, establishes training and education programs for engineers and GHP installers, and assists industry and utilities in disseminating information to A&E firms and potential customers. The goal is to achieve the installation of 400,000 units per year by 2000, which will shave peak electricity demand by 5000 MWe, reducing annual carbon dioxide emissions by 1.5 MMTCE (29).

Research and Technology Needs

The growth of geothermal energy development is not limited by resource availability. Rather, it is limited by inadequate technology. Only the very highest-grade geothermal resources can be economically used today for the generation of electricity. Development of the vast majority of geothermal resources is not possible because, at most resource sites, power-generation costs are higher than those for competing fossil fuels, especially natural gas. Geothermal costs today range from \$0.04 to \$0.07 per kWh for new power development at high-grade geothermal resource sites, whereas new generation capacity from natural gas, where it is readily available, produces power at \$0.025–\$0.05 per kWh. (Operation and maintenance costs at geothermal power plants whose capitalization has been paid may be as low as \$0.009 per kWh.) Power-generation costs at the much more plentiful lower-grade geothermal resource sites are not able to compete today with natural-gas generation costs in the United States. A core R&D program aimed at improving existing technology and developing new, advanced technology is critical to enable the geothermal industry to compete in the domestic and global energy marketplaces. Well-funded R&D programs in Japan and Europe (53) are aimed at advancing heat mining technology beyond that of the United States.

During the past several years, the geothermal industry has conducted a series of workshops to discuss needs for new technology. These workshops identified three primary research areas—drilling, exploration and reservoir technology, and energy conversion (112, 113).

DRILLING Drilling the required production and injection wells is one of the most capital-intensive activities in a geothermal development. Because of the high temperatures and corrosive nature of geothermal fluids, geothermal drilling is much more difficult and expensive than conventional oil and gas drilling. In addition, geothermal wells are of larger diameter than oil and gas wells in order to support high flow rates, e.g. 25–320 kg s^{-1} (200,000 to 2,500,000 lbs hr^{-1}). A typical cost is \$1–3 million (see Figure 5) for a geothermal well that will support 3–5 MWe of dry-steam or flashed-steam electrical capacity. Drilling costs account for one third to one half of the total costs for a geothermal project. Improvement in existing drilling techniques and development of new, advanced drilling techniques would significantly lower the cost of electricity generated from geothermal resources. The industry believes that drilling costs can be lowered by 10–20% in the short term (the next decade), through incremental improvements to existing technology, and by 30–50% through development of advanced techniques such as those proposed in the DOE's National Advanced Drilling and Excavation Technologies (NADET) program (113, 114).

EXPLORATION AND RESERVOIR TECHNOLOGY The major problem in exploration is how to remotely detect producing zones deep in the subsurface so that drill holes can be sited and steered to intersect these producing zones. No two geothermal reservoirs are alike, and their permeabilities (ability to transmit geothermal fluids to the well bore) vary widely over short distances.

Present exploration techniques are not specific enough and lead developers to drill too many dry wells, driving up development costs. Further, inadequate knowledge of the physical and chemical properties of the subsurface makes it impossible to mine the heat in the most efficient way and ensure the sustainability of geothermal reservoirs. Increased knowledge of rock mechanics is needed to provide improved techniques for creating new fractures, and better well-stimulation methods are needed to open existing fractures and lower flow impedance. Better geological, geochemical, and geophysical techniques, as well as improved computer methods for modeling heat-extraction strategies from geothermal reservoirs, are needed. It is possible that geothermal development costs could be lowered by 10–20% and that reservoir lifetimes could be extended significantly with improvements in earth science techniques.

ENERGY CONVERSION The efficiency in conversion of geothermal steam into electricity in the power plant directly affects the cost of power generation. During the past decade, the efficiency of dry- and flash-steam geothermal power plants has been improved by 25%. Power plants installed at The Geysers geothermal field in California during the 1960s required 9 kg (20 lbs) of steam to produce 1 kWh of electricity, i.e. 2.5 kg s^{-1} of dry steam per MWe, or 10–15 kg s^{-1} per 5-MWe well. The newest plants at The Geysers, installed in the mid and late 1980s, require only 6.6 kg (14.5 lbs) of steam to produce that same kilowatt-hour of electricity, i.e. 1.8 kg s^{-1} of dry steam per MWe or 9–11 kg s^{-1} per 5-MWe well. Geothermal power-plant efficiency probably can be improved at least 25% more over the next decade with a modest investment in R&D.

EPILOGUE

The geothermal energy resource base is large and well distributed globally. Geothermal power, generated from these resources, has grown steadily since the early 1920s at a robust rate of 8.5% per year, reaching 7000 Mwe installed capacity by 1997. In certain regions, geothermal power makes a significant contribution; for example, approximately 7% of California's electricity is produced from geothermal energy.

Geothermal power plants offer several advantages; they are simple, safe, and modular (1–50 MWe), have short construction periods (approximately one year for a 50-MWe plant), and are capable of providing base, load-following, or peaking capacity. Geothermal plants provide significant societal benefits; they reduce the demand for imported oil with its accompanying national defense and balance-of-payments problems and offer benign environmental attributes (negligible emissions of CO_2, SO_x, NO_x, and particulates, and modest land and water use). These features are compatible with the sustainable growth of global energy supplies, making geothermal energy an attractive option.

Today, the growth in geothermal power has been based exclusively on the use of high-temperature ($T > 150°C$) hydrothermal resources. If geothermal power is to become more universally available and have a significant impact on global energy supplies in the next century, then low-temperature hydrothermal resources and other advanced concepts (including hot dry rock, geopressured, and magma) must be vigorously pursued to make them economically competitive. This will require an aggressive advanced research program to reduce field development (especially drilling and stimulation) costs and increase energy conversion efficiencies.

Lower-temperature hydrothermal resources ($T < 150°C$) also provide an economical source of energy for GHPs and for direct use in domestic, industrial, agricultural, aquaculture, and district heating applications. The installation of GHPs in the United States has been growing rapidly—over 15% per year—over the past decade. GHPs offer users an inexpensive source of space heating and cooling, along with domestic hot water, while offering utilities the benefits of reduced peak demands for power, and the deferred need for additional plant capacity.

Research efforts continue in Europe, Japan, and the United States in order to increase our understanding and improve technology for heat mining in the more challenging environments of hot dry rock and magma resources. If successful, these efforts will make geothermal energy a competitive option available to everyone.

ACKNOWLEDGMENTS

The authors wish to express their appreciation to G Bloomquist, H Herzog, M Kutney, A Jelacic, T Meidav, B Skalak, R Socolow, and T Sparks for their kind assistance and valuable suggestions. We are especially grateful to B Caputo for her word processing skills in preparing the manuscript.

Literature Cited

1. Brown LR, Flavin C, Postel S. 1990. *Picturing a Sustainable Society: State of the World, A Worldwatch Institute Report on Progress Toward a Sustainable Society.* New York/London: Norton. 17 pp.
2. Gore A. 1993. *Earth in the Balance—Ecology and the Human Spirit.* New York: Penguin Group. 408 pp.
3. McLeod JT. 1995. Sustainable management of geothermal resources—a New Zealand scenario. *Proc. World Geotherm. Congr. 1995,* 1:569–73. Florence: Int. Geotherm. Assoc.
4. Serageldin I, Steer A, eds. 1994. Making development sustainable—from concepts to action. *Environmentally Sustain-*

able Dev. Occas. Pap. No. 2. Washington, DC: World Bank. 40 pp.
5. Nelson RH. 1995. Sustainability and God: economic values of the sustainability debate. *Annu. Rev. Ecol. Syst.* 26:135–34
6. Herzog HJ, Drake EH. 1994. Carbon dioxide recovery and disposal from large energy systems. *Annu. Rev. Energy Environ.* 21:145–66
7. Brundtland Commission. 1987. *Our Common Future: World Commission on Environment and Development (The Brundtland Commission)*. New York: Oxford Univ. Press
8. Schmidheiny S. 1992. *Changing Course: A Global Business Perspective on Development and Environment.* Bus. Counc. Sustainable Dev., Cambridge, MA: MIT Press
9. Wright PM. 1995. The sustainability of production from geothermal resources. *Proc. World Geotherm. Congr. 1995,* 4:2825–36. Florence: Int. Geotherm. Assoc.
10. Rowley JC. 1982. Worldwide geothermal resources. See Ref. 57, pp. 44–176
11. Armstead HCH, Tester JW. 1987. *Heat Mining.* London: E & FN Spon. 478 pp.
12. Kozloff KL, Dower RC. 1993. *A New Power Base—Renewable Energy Policies for the Nineties and Beyond.* Washington, DC: World Resour. Inst. 196 pp.
13. Armstead HCH. 1983. *Geothermal Energy.* London: E & FN Spon. 404 pp. 2nd ed.
14. DiPippo R. 1980. *Geothermal Energy as a Source of Electricity.* Washington, DC: US Gov. Print. Off. 370 pp.
15. Duchane D. 1994. Geothermal energy. In *Encyclopedia of Chemical Technology*, 12:512–39. New York: Wiley
16. Kruger P, Otte C. 1972. *Geothermal Energy Resources, Production, Stimulation.* Stanford, CA: Stanford Univ. Press. 360 pp.
17. Geo-Heat Center. 1988. *Geothermal direct use developments in the United States. GHC Tech. Rep.,* Oregon Inst. Technol., Klamath Falls, OR
18. Lienau PJ, Lunis BC, eds. 1991. *Geothermal Direct Use Engineering and Design Guidebook.* Klamath Falls, OR: Oregon Inst. Technol. Geo-Heat Cent. 445 pp.
19. Lienau PJ, Lund JW, Culver GG. 1995. Geothermal direct use in the United States update: 1990–1994. *GHC Q. Bull.* 16 (No. 2):1–6
20. Bloomquist G. 1991. Regulatory and commercial aspects. See Ref. 18, pp. 395–435
21. Wright PM. 1991. Exploration for direct heat resources. See Ref. 18, pp. 55–98
22. Rafferty K. 1994. Greenhouse heating equipment selection spreadsheet. *GHC Q. Bull.* 16 (No. 1):12–15
23. Rafferty K. 1994. *A spreadsheet for geothermal direct use cost evaluation. GHC Tech. Rep.,* Geo-Heat Cent., Oregon Inst. Technol., Klamath Falls, OR
24. Lienau PJ, Ross HP, Wright PM. 1995. Low-temperature resource assessment. *Trans. Geotherm. Resour. Counc.* 19:63–68
25. Lienau PJ, Ross HP. 1996. *Low-temperature resource assessment program. Final Rep.,* Geo-Heat Cent., Oregon Inst. Technol., Klamath Falls, OR
26. Reed MJ, ed. 1983. Assessment of low-temperature geothermal resources of the United States—1982. *US Geol. Surv. Circ. 892.* 73 pp.
27. Rafferty K. 1996. A capital cost comparison of commercial ground-source heat pump systems. *Proc. Geotherm. Prog. Rev. 14th* , ed. AJ Jelacic, pp. 261–65. Washington, DC: DOE
28. International Ground Source Heat Pump Association. 1995. *Geothermal Heating, Cooling, and Water Heating Systems.* Stillwater, OK: IGSHPA
29. Pratsch LW. 1995. *Geothermal: a household word by the year 2000.* Presented at Int. Energy Environ. Congr. Assoc. Energy Eng., Richmond, VA
30. L'Ecuyer ML, Zoi C, Hoffman J. 1993. *Space conditioning: the next frontier, EPA Rep. 430-R-93-004,* Environ. Prot. Agency, Washington, DC
31. Keller JG. 1977. *Heat pumps: primer for use with low-temperature geothermal resources. INEL Rep. GP-118.* Idaho Natl. Eng. Lab., Idaho Falls
32. Bloomquist RG. 1981. Proc. Low Temperature Utilization, Heat Pump Applications, District Heating. *WAONG-81-05.* Olympia, WA: Washington State Energy Off.
33. Painter J. 1984. Warm-water well cuts power costs. *Public Power* Jan./Feb:34–35
34. The Geothermal Heat Pump Consortium. 1995. *National Earth Comfort Program: Technology, Elements, Goals, and Objectives.* Washington, DC: GHPC
35. Brook CA, Mariner RH, Mabey DR, Swanson JR, Guffanti M, Muffler LPJ. 1979. Hydrothermal convection systems with reservoir temperatures $>=$ 90°C. See Ref. 88, pp.
36. Wright PM. 1991. Exploration potential for new hydrothermal resources for electrical power generation in the 48 con-

tiguous states. *Trans. Geotherm. Resour. Counc.* 15:217–28

37. Wright PM. 1996. IEA Task V—sustainability of geothermal energy utilization. *Trans. Geotherm. Resour. Counc.* 20:271–72
38. Tester JW. 1982. Energy conversion and economic issues for geothermal energy. See Ref. 57, pp.
39. Meidav T, Pigott J. 1994. The impact of geothermal energy development on employment. *Trans. Geotherm. Resour. Counc.* 18:55–60
40. US Dep. Energy/Energy Information Admin. 1995. *Renewable Energy Annual—1995. DOE/EIA-0603(95).* Washington, DC: US DOE/EIA. 158 pp.
41. Geothermal Energy Association. 1995. *Geothermal Energy—Clean, Sustainable Energy for the Benefit of Mankind and the Environment.* Brochure. Washington, DC: GEA. 6 pp.
42. US Dep. Energy/Energy Information Admin. 1996. *Emissions in Greenhouse Gases in the United States—1995. DOE/EIA-0603(95).* Washington, DC: DOE/EIA. 140 pp.
43. Goddard WB, Goddard CB, McClain DW. 1989. Future air quality maintenance and improvements through the expanded use of geothermal energy. *Trans. Geotherm. Resour. Counc.* 13:27–32
44. Goddard WB, Goddard CB. 1990. Energy fuel sources and their contribution to recent global air pollution trends. *Trans. Geotherm. Resour. Counc.* 14:643–49
45. Enedy SL, Enedy KL, Maney J. 1991. Reservoir response to injection in the Southeast Geysers. In *Monograph on the Geysers Geothermal Field. Geotherm. Resour. Counc. Spec. Rep. No. 17,* pp. 211–19
46. Voge E, Koenig B, Smith BJS, Enedy S, Beall JJ, et al. 1994. Initial findings of The Geysers Unit 18 cooperative injection project. *Trans. Geotherm. Resour. Counc.* 18:353–57
47. Pruess K, Enedy S. 1993. Numerical modeling of injection experiments at The Geysers. *Proc. 18th Workshop Geotherm. Reservoir Eng.,* pp. 63–67. Stanford Univ., Stanford, CA, 26-28 Jan., 1996
48. Dellinger M. 1996. Turning community wastes into sustainable geothermal energy—the S.E. Geysers effluent pipeline project. *Trans. Geotherm. Resour. Counc.* 20:205–8
49. Geothermal Energy Association. 1993. *Geothermal Energy in Developing Countries—Opportunities for Export of U.S. Goods and Services.* Brochure. Washington, DC: Natl. Geotherm. Assoc. 4 pp.
50. Ehara S, Fujimitsu Y. 1995. The nature and occurrence of geothermal resources in Japan—a review. *Trans. Geotherm. Resour. Counc.* 19:311–16
51. Muffler LJP, Gaffanti M, eds. 1978. Assessment of geothermal resources in the United States. *US Geol. Surv. Circ.* 790
52. Sass JH. 1996. Hot dry rock and the U.S. Geological Survey: a question of priorities. *Geotherm. Resour. Counc. Bull.* 25(8):313–15
53. US Geological Survey. 1993. *Potential of hot-dry-rock geothermal energy in the eastern United States. USGS Open File Rep. 93-377,* USGS, Washington, DC
54. Brown LA, Kane H, Ayres E. 1993. Geothermal power gains. *Vital Signs 1993* 99:54–55
55. Huttrer GW. 1995. The status of world geothermal power production 1990–1994. *Proc. World Geotherm. Congr. 1995, Florence.* Taupo, New Zealand: Int. Geotherm. Assoc.
56. DiPippo R. 1995. Geothermal electric power production in the United States: a survey and update for 1990–1994. *Proc. World Geotherm. Congr. 1995, Florence.* Taupo, New Zealand: Int. Geotherm. Assoc.
57. Edwards LM, Chilingar GV, Rieke HH III, Fertl WH, eds. 1982. *Handbook of Geothermal Energy.* Houston: Gulf. 613 pp.
58. Wright PM. 1996. Overview of business considerations for geothermal projects in developing countries. *Trans. Geotherm. Resour. Counc.* 20: 551–53
59. Knapp GM. 1996. Business and financial issues for international power projects. *Trans. Geotherm. Resour. Counc.* 20: 529–50
60. Tester JW, Brown DW, Potter RM. 1989. *Hot Dry Rock Geothermal Energy—A New Energy Agenda for the 21st Century. LA-11514-MS.* Los Alamos, NM: Los Alamos Natl. Lab.
61. Nadis S, MacKenzie JJ. 1993. *Car Trouble.* Washington, DC: World Resour. Inst.
62. Kruger P, Fioravanti MD. 1995. *Excess baseload geothermal electricity for production of hydrogen.* Presented at Int. Hydrogen Clean Energy Symp. ‘95, Tokyo
63. Salisbury DF. 1995. Kruger revives notion of hydrogen economy. *Stanford Rep. 28th* , No. 18, p.1
64. Stucki S. 1991. The cost of electrolytic hydrogen from off-peak power. *Int. J. Hydrogen Energy* 16(7):461–67

65. Braun GW, Suchard A, Martin J. 1991. Hydrogen and electricity as carriers of solar and wind energy for the 1990s and beyond. *Solar Energy Mater.* 24:62–75
66. Jonsson VK. 1992. Feasibility of using geothermal energy in hydrogen production. *Geothermics* 21(5/6):673–81
67. Kruger P. 1996. *Long-term potential for air quality improvement in the Tokyo metropolitan area from use of hydrogen fuel in transportation.* Presented at 1st WE-NET Int. Workshop, Tokyo
68. Duchane D, Brown DW, Albright J, Fehler M, Dash Z, et al. 1991–1993. *Long-term flow-test operating plan and preliminary results in the phase II hot dry rock reservoir, Fenton Hill, NM. Memoranda and Draft Rep.,* Los Alamos Natl. Lab., Los Alamos, NM
69. Sato Y, Ishibashi K. 1994. Technology developments in the Japanese HDR project at Hijiori. *Trans. Geotherm. Resour. Counc.*
70. Sato Y, Ishibashi K, Yamaguchi T. 1995. Status of Japanese HDR project at Hijiori. *Proc. World Geotherm. Congr. 1995. Florence* Taupo, New Zealand: Int. Geotherm. Assoc.
71. Kappelmeyer O, et al. 1991. European HDR Project at Soultz-sous-Forets General Presentation. *Geotherm. Sci. Technol.* 2(4):263–89
72. Batchelor AS. 1984. Hot dry rock geothermal exploitation in the United Kingdom. *Mod. Geol.* 9:1–41
73. Batchelor AS. 1987. Development of hot dry rock systems in the UK. *IEE Proc. A* 134(5):371–80
74. Parker R. 1989. Hot dry rock geothermal energy research at the Camborne School of Mines. *Geotherm. Resour. Counc. Bull.* 18(9):3–7
75. Duchane D. 1991. International programs in hot dry rock technology development. *Geotherm. Resour. Counc. Bull.* May:135–42
76. Tester JW, Herzog HJ. 1990. *Economic Predictions for Heat Mining: A Review and Analysis of Hot Dry Rock (HDR) Geothermal Energy Technol. MIT-EL-90-001.* MIT Energy Lab., Cambridge, MA
77. Tester JW, Herzog HJ. 1991. The economics of heat mining: an analysis of design options and performance requirements for hot dry rock (HDR) geothermal power systems. *Energy Syst. Policy* 25:33–63
78. Tester JW, Herzog HJ, Chen Z, Potter RM, Frank MG. 1994. Prospects for universal geothermal energy from heat mining. *Sci. Glob. Secur.* 5:99–121
79. Herzog HJ, Tester JW, Frank MG. 1997. Economic analysis of heat mining. *Energy Sources* 19:19–33
80. RTZ Consultants Limited. 1991. *Conceptual Design Study for a Hot Dry Rock Geothermal System. ETSU G 153.* Harwell, UK: Dep. Energy
81. Colp J. 1982. *Sandia Natl. Lab. Rep. SAND 82-2377,* Sandia Natl. Lab., Albuquerque, NM
82. Gerlach TM. 1982. *Analysis of magmathermal conversion of biomass to gaseous fuel. Sandia Natl. Lab. Rep. SAND 82-0031,* Sandia Natl. Lab., Albuquerque, NM
83. Finger TJ. 1992. *Proc. Geotherm. Progr. Rev. 10th,* pp. 127–28. Washington, DC: DOE
84. Crewdson RA, Martin WF, Taylor DL, Bakhtar K. 1991. *An evaluation of technology and economics of extracting energy from magma resources for electric power generation. Rep. Mine Dev. Eng. Co.,* Bakersfield, CA
85. Beeland GV. 1986. A decade of geothermal development in the United States. *GRC Bull.* 15(8):27–33
86. Negus-de Wys J. 1992. *Geopresssured-geothermal energy: the untapped resource. INEL Rep. BP633-0792.* Idaho Natl. Eng. Lab, Idaho Falls
87. Lombard DB, Goldsberry FL. 1988. Geopressured brine well tests. *Geotherm. Sci. Technol.* 1(3):225–51
88. Muffler LJ, ed. 1979. Assessment of geothermal resources of the United States. *US Geol. Surv. Circ. 790.* Washington, DC: USGS
89. Wallace RH, Kraemer TF, Taylor RE, Wesselman JB. 1979. Assessment of geopressured-geothermal resources in the northern Gulf of Mexico basin. See Ref. 88, pp. 132–55
90. US Dep. Energy. 1991. *Geothermal energy program overview. DOE Rep. No. DOE-CH 10093-95*
91. Mock JE, ed. 1992. *Proceedings geothermal energy and the utility market, San Francisco. DOE Rep. CONF/920378,* Dep. Energy, Washington, DC
92. Eaton BA, Featherston CR, Meahl TE. 1992. Geothermal well operations and automation in a competitive market. See Ref. 91, pp. 169–75
93. Negus-de Wys J. 1992. Technology transfer, reaching the market for geopressured-geothermal resources. See Ref. 91, pp. 187–90
94. Campbell RG, Hattar MM. 1991. *Design and operation of a geopressured-geothermal hybrid cycle power plant.*

Holt Rep. 30008, Ben Holt Co., Pasadena, CA

95. Negus-de Wys J, ed. 1990. *Proc. Indus. Consortium Utilization Geopressured-Geothermal Resour.,* Vol. 2. Idaho Falls, ID: Idaho Natl. Eng, Lab.
96. Tester JW, Holgate HR. 1993. Supercritical water oxidation technology: a review of process development and fundamental research. In *Emerging Technologies in Hazardous Waste Management,* ed. DW Tedder, FG Pohland. ACS Symp. Ser. 518, Ch 3. Washington, DC: Am. Chem. Soc.
97. Evans J. 1989. Supercritical oxidation. *Energy Stud.* 14(4). Austin, TX: Univ. Texas, Cent. Energy Stud.
98. Deutch JM. 1993. Foreword. See Ref. 101, p. iii
99. Cambel AB, Mock JE. 1995. Expediting technology transfer with multimedia. *Technol. Forecast. Soc. Change* 48:1–5
100. Mock JE. 1990. *Lessons learned from successful R&D cooperative agreements.* Presented at Stevenson-Wydler 10 Years Later, Fed. Lab. Fall Meet., Atlanta
101. Mock JE, Kenkeremath DC, Janis FT. 1993. *Moving R&D to the Marketplace: A Guidebook for Technology Transfer Managers.* Washington, DC: DOE
102. Falcone S. 1995. *Technology transfer impact profiles. UNM Rep. AM 3455,* Univ. New Mexico, Albuquerque
103. Schochet DN, Mock JE. 1994. How the Department of Energy loan guaranty program paved the way for the growth of the geothermal industries. *Geotherm. Resour. Counc. Bull.* Sept./Oct:297–302
104. Mock JE. 1994. *Over 20 years of transfer of DOE/industry geothermal technology developments enhance the nation's ability to meet environmental goals.* Presented at DOE 12th Annu. Geotherm. Prog. Rev., San Francisco
105. Dellinger M. 1996. *Turning community wastes into sustainable energy.* Presented at DOE 14th Annu. Geothermal Prog. Rev., Berkeley, CA
106. National Renewable Energy Laboratory. 1993. *Office of Utility Technologies success stories. DOE Rep. 92001193,* Natl. Renewable Energy Lab., Golden, CO
107. Sandia National Lab. 1996. *FY97 Geothermal R&D Program Plan. SNL Rep.,* Sandia Natl. Lab., Albuquerque, NM. 225 pp.
108. Mock JE, Beeland GV. 1992. U.S. Department of Energy support of growth in industrial use of geothermal energy. *Geothermics* 21:939–46
109. US Dep. Energy. 1993. *The Climate Change Action Plan.* Washington, DC: USDOE
110. US Dep. Energy. 1993. Preface. See Ref. 109
111. US Dep. Energy. 1993. See Ref. 109, p. 5
112. Wright PM. 1994. A study of the geothermal industry's R&D priorities. *Trans. Geotherm. Resour. Counc.* 18:139–48
113. Wright PM. 1996. *Geothermal energy R&D—investment in America's future: statement of the geothermal energy association.* Presented before Subcomm. Energy Water Dev., Comm. Appropr., US House Represent., Feb. 29. 5 pp.
114. NADET. 1993. *A Proposed National Program for Advanced Drilling and Excavation Technologies.* Cambridge, MA: MIT Energy Lab.

Annual Review of Energy and the Environment
Volume 22, 1997

CONTENTS